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Supreme Court, U.S.
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In The

Supreme Court of the United States

ENVIRONMENTAL DEFENSE, *et al.*,

Petitioners,

v.

DUKE ENERGY CORPORATION, *et al.*,

Respondents.

On Writ Of Certiorari To The United States Court Of Appeals For The Fourth Circuit

JOINT APPENDIX
VOLUME I, Pages 1 to 265

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United States Court of Appeals for the Fourth Circuit:

Order Requesting Supplemental Briefing (May 2, 2005) ..... Pet. App. 21a

Opinion (June 15, 2005) ..... Pet. App. 1a-19a

Order Denying Petitions for Rehearing and Rehearing En Banc (Aug. 30, 2005) ..... Pet. App. 20a

RELEVANT DOCKET ENTRIES

U.S. District Court
Middle District of North Carolina (Durham)
CIVIL DOCKET FOR CASE
USA v. Duke Energy Corp.
#: 00-CV-1262

Date Filed	Docket Entry #	Description
12/22/00	1	Complaint filed. (Entry date: 12/28/00)
3/12/01	3	Answer to Complaint and Counterclaim by Duke Energy Corp. (Attorneys DANIEL W. FOUTS, T. THOMAS COTTINGHAM III) against USA; Answer due on 4/1/2001 for USA. (Entered: 03/13/2001)
5/8/01	5	Motion by Environmental Def., NC Sierra Club, NC Public Interest to Intervene as Plaintiffs (Entered: 05/09/2001)
9/6/01	24	MEMORANDUM OPINION on applicants' motion to intervene; applicants have a statutory right to intervene and their motion to intervene will be granted pursuant to Rule 24(a)(1) of the Fed.R.Civ.P.; applicants' participation in the litigation will be coordinated with that of the Plaintiff United States to ensure the efficient adjudication of this case; an order in accordance with this memorandum opinion shall be entered contemporaneously herewith (signed by JUDGE FRANK W. BULLOCK JR.) (EOD Date 9/6/01).

9/6/01	25	ORDER, for the reasons set forth in the memorandum opinion filed contemporaneously herewith, that Applicants Environmental Defense, North Carolina Sierra Club, and North Carolina Public Interest Research Group Citizen Lobby/Education Fund's motion to intervene [Doc. #5] is GRANTED (signed by JUDGE FRANK W. BULLOCK JR.) (EOD Date 9/6/01).
9/6/01	26	Complaint in Intervention (Entered: 09/06/2001)
10/9/01	35	ANSWER to Plaintiffs-Intervenors' Complaint by DUKE ENERGY CORP. (Entered: 10/11/2001)
12/18/02	94	MEMORANDUM OPINION re: the United States' motion for leave to amend the complaint; an order in accordance with this memorandum opinion shall be entered contemporaneously herewith (signed by JUDGE FRANK W. BULLOCK JR.) (EOD Date 12/18/02).
12/18/02	95	ORDER, for the reasons set forth in the memorandum opinion filed contemporaneously herewith, that the motion [Doc. #72] of the United States for leave to file an amended complaint is DENIED * * * (signed by JUDGE FRANK W. BULLOCK JR.) (EOD Date 12/18/02).
1/31/03	128	MOTION for Summary Judgment on all of Plaintiff's and Intervenors' claims that Duke violated the New Source Review provision of the Clean

		Air Act and related States Implementation Plan provision of North and South Carolina by defendant DUKE ENERGY CORP. (Entered: 02/03/2003)
1/31/03	129	Brief, with Appendices in Five (5) Volumes . . . by Duke Energy Corp. in Support of [128-1] Motion for Summary Judgment * * * (Entered: 02/03/2003)
1/31/03	130	MOTION for Partial Summary Judgment on Defendant's Defenses of "Fair Notice" and JOINDER IN MOTION for Partial Summary Judgment by the United States on the applicable legal test for "routine maintenance"; on Defendant's defenses on "routine maintenance", emissions calculations and defendant's "statute of limitations" defenses by intervenor-plaintiffs NC PUBLIC INTEREST, NC SIERRA CLUB, and ENVIRONMENTAL DEF. (Entered: 02/03/2003)
1/31/03	131	Brief, with Exhibits 1-21, by NC Public Interest, NC Sierra Club, Environmental Def. in Support of [130-1] Motion * * * (Entered: 02/03/2003)
1/31/03	132	MOTION for Partial Summary Judgment on the applicable legal test for "routine maintenance," Defendant's defenses of "fair notice" and "routine maintenance", calculation of emissions, and defendant's "statute of limitations" defenses by plaintiff USA (Entered: 02/03/2003)
3/31/03	152	RESPONSE by USA to [128-1] motion for Summary Judgment on all of

		Plaintiff's and Intervenors' claims that Duke violated the New Source Review provision of the Clean Air Act and related States Implementation Plan provision of North and South Carolina by DUKE ENERGY CORP. (Entered: 04/01/2003)
3/31/03	158	RESPONSE BRIEF IN OPPOSITION, with Supplemental Appendix of Exhibits in four (4) Volumes, by DUKE ENERGY CORP. to [132-1] motion for Partial Summary Judgment * * * (Entered: 04/01/2003)
3/31/03	159	BRIEF IN RESPONSE with Exhibits by ENVIRONMENTAL DEF., NC SIERRA CLUB, NC PUBLIC INTEREST to [128-1] motion for Summary Judgment * * * (Entered: 04/01/2003)
3/31/03	160	RESPONSE BRIEF IN OPPOSITION by DUKE ENERGY CORP. to [130-1] motion for Partial Summary Judgment on Defendant's Defenses of "Fair Notice" by Plaintiff-Intervenors, ENVIRONMENTAL DEF., NC SIERRA CLUB, NC PUBLIC INTEREST (Entered: 05/12/2003)
4/25/03	174	AMENDED RESPONSE BRIEF IN OPPOSITION, with attachments, by DUKE ENERGY CORP. to Plaintiff's [132-1] motion for Partial Summary Judgment on the applicable legal test for "routine maintenance," Defendant's defenses of "fair notice" and "routine maintenance", calculation of emissions, and defendant's "statute of limitations" defenses (Entered: 04/28/2003)

4/30/03	185	REPLY by DUKE ENERGY CORP. to Plaintiff-Intervenors' response to [128-1] motion for Summary Judgment * * * (Entered: 05/01/2003)
4/30/03	186	REPLY by DUKE ENERGY CORP. to Plaintiff, USA's response to [128-1] motion for Summary Judgment * * * (Entered: 05/01/2003)
4/30/03	187	SECOND SUPPLEMENTAL APPENDIX OF EXHIBITS in one (1) volume by DUKE ENERGY CORP. in support of [128-1] motion for Summary Judgment * * * (Entered: 05/01/2003)
4/30/03	188	REPLY, with Exhibits 1 & 2, by Plaintiff-Intervenors' NC PUBLIC INTEREST, NC SIERRA CLUB, ENVIRONMENTAL DEF. in support of [130-1] Motion Summary Judgment on Fair Notice (Entered: 05/01/2003)
4/30/03	189	REPLY, with Appendix A and supporting Exhibits 156-165, by USA to response to [132-1] motion for Partial Summary Judgment * * * (Entered: 05/01/2003)
7/18/03		Motion hearing held re: [132-1] motion for Partial Summary Judgment * * * , [130-1] motion for Partial Summary Judgment * * * , [128-1] motion for Summary Judgment * * * held before USDJ Frank W. Bullock, Jr. * * * (Entered: 07/21/2003)
8/13/03	231	TRANSCRIPT of ORAL ARGUMENTS ON MOTIONS FOR SUMMARY JUDGMENT filed, held before

JUDGE FRANK W. BULLOCK, JR. * * * (Entered: 08/14/2003)

8/26/03 234 MEMORANDUM OPINION that, for the reasons set out, the court will grant in part and deny in part the EPA's motion for partial summary judgment in which Intervenor-Plaintiffs join; * * * (signed by JUDGE FRANK W. BULLOCK JR.) (Entered: 08/26/2003)

8/26/03 235 ORDER AND JUDGMENT, for the reasons set forth in the memorandum opinion filed contemporaneously herewith, that Duke Energy's motion for summary judgment [Doc. #128] is DENIED; further ORDERED that the United States' motion for partial summary judgment [Doc. #132] on the applicable legal tests for "routine maintenance" and calculation of emissions, and on Duke Energy's defenses of "fair notice" and "routine maintenance", in which Intervenor-Plaintiffs join [Doc. #130], is DENIED; further ORDERED AND ADJUDGED that the United States' motion for partial summary judgment [Doc. #132] on Duke Energy's defense that the statute of limitations bars the United States' claims arising from activities occurring prior to December 22, 1995, in which Intervenor-Plaintiffs join [Doc. #130], is GRANTED; further ORDERED that Intervenor-Plaintiffs' motion for partial summary judgment [Doc. #130] on Duke Energy's defense of "fair notice" is DENIED; further

		ORDERED that Duke Energy's motion for partial judgment on the pleadings [Doc. #37] is DENIED. Remaining for trial are the issues of whether Duke Energy's projects were routine maintenance, repair, and replacement as defined relative to the industrial category and whether Duke Energy's projects caused an increase in annual net emissions, assuming constant hours and conditions of operation (signed by JUDGE FRANK W. BULLOCK JR.) (Entered: 08/26/2003)
12/23/03	268	MOTION by USA for Reconsideration of [235-1] judgment and [234-1] order or, in the alternative, to certify orders for interlocutory appeal and for stay pending appeal. (Entered: 12/29/2003)
12/29/03	270	Response by NC Public Interest, NC Sierra Club, Environmental Def., to the [268-1] USA's Motion for Reconsideration * * * (Entered: 12/30/2003)
2/23/04	294	ORDER denying [268-1] motion for Reconsideration of [235-1] judgment and [234-1] order or, in the alternative, to certify orders for interlocutory appeal and for stay pending appeal. The court will direct the Clerk to schedule this case for trial during the July term and provide proper notice to the parties; signed by JUDGE FRANK W. BULLOCK JR. (J. Wilson) (Entered: 02/23/2004)

4/13/04	311	STIPULATIONS by all parties in support of Joint Motion for entry of final Judgment, to stay consideration of Rule 72(a) Objections, and to stay enforcement of discovery Order (Entered: 04/13/2004)
4/14/04	313	ORDER AND FINAL JUDGMENT signed by JUDGE FRANK W. BULLOCK JR., that Summary Judgment is granted in favor of Defendant Duke Energy on Plaintiff's and Plaintiff-Intervenors' PSD claims in this action. * * * (Entered: 04/15/2004)
6/10/04	314	NOTICE OF APPEAL to USCA 4th Circuit by NC PUBLIC INTEREST, NC SIERRA CLUB and ENVIRONMENTAL DEFENSE of [313-1] Final Order and Judgment (Entered: 06/14/2004)
6/10/04	315	NOTICE OF APPEAL to USCA 4th Circuit by USA of [313-1] Final Order and Judgment (Entered: 06/14/2004)

US Court of Appeals for the Fourth Circuit
GENERAL DOCKET FOR CASE
United States, et al v. Duke Energy Corp.
No. 04-1763

Date	Description
6/24/04	Civil Case Docketed.
2/3/05	Oral argument heard. Panel: Honorable J.M. Luttig, Honorable Diana G. Motz, Honorable Samuel G. Wilson. [04-1763] (su)
5/2/05	Court Order to file Supplemental Briefs.
6/15/05	Judgment Order filed. Decision: AFFIRMED.
8/1/05	Petition Filed by Appellant Environmental Defense, NC Sierra Club, Appellant NC Public Interest for rehearing/ rehearing en banc
8/1/05	Petition filed by Appellant USA for rehearing * * * and rehearing en banc.
8/30/05	Court Order filed Denying all Motions for Rehearing; Motions for Rehearing *En Banc*
9/7/05	Mandate Issued.

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	CIVIL NO. 1:00CV1262
v.	)	
DUKE ENERGY CORPORATION,	)	
Defendant.	)	

ORDER

(Filed Sep. 6, 2001)

BULLOCK, District Judge

For the reasons set forth in the memorandum opinion filed contemporaneously herewith,

IT IS ORDERED that Applicants Environmental Defense, North Carolina Sierra Club, and North Carolina Public Interest Research Group Citizen Lobby/Education Fund's motion to intervene [Doc. #5] is GRANTED.

September 6, 2001

/s/ _____
United States District Judge

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	CIVIL NO. 1:00CV1262
v.	)	
DUKE ENERGY CORPORATION,	)	
Defendant.	)	

EXHIBITS IN SUPPORT OF DUKE'S
MOTION FOR SUMMARY JUDGMENT

(Filed Jan. 31, 2003)

* * *

EXHIBIT 9

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAY 9 1986

THE ADMINISTRATOR

Honorable John D. Dingell
Chairman
Committee on Energy and Commerce
House of Representive
Washington, D.C. 20515

Dear Mr. Chairman:

On April 14, 1986 you requested that I respond to a number of questions regarding H.R. 4567, the "Acid Deposition Control Act of 1986." Given the seriousness of both the proposal and its potential consequences over the next 20 years, I believe deliberate and thorough consideration should be given to your questions and to the impact of this proposed legislation. We also wish to be timely and helpful with respect to the Committee's rapid deliberations on H.R. 4567. Therefore, the enclosure provides preliminary answers to questions 1 through 7, 9, 11 through 23, and 25. We may wish to provide revised answers to these questions after more careful review and analysis. Any revised answers and answers to the remaining questions will be provided as soon as possible.

I should point out that these answers have not yet been reviewed by all Interested Agencies of the Administration and, therefore, can be said to reflect only EPA's assessment.

Sincerely,

/s/ Lee M. Thomas
Lee M. Thomas

76. *Acid Deposition Control Act of 1986 (Part 1): Hearing on H.R. 4567 Before the Subcomm. on Health and the Env't of the House Comm. on Energy and Commerce*, 99th Cong., 439, 446-449 (1986) (material submitted for the record by Environmental Protection Agency, responses to questions submitted by April 14, 1986, letter from John D. Dingell). Hearings Volume XVIII – 4/29/86.

Question 2.a.

According to a March 3, 1986 letter from the Environmental Protection Agency (EPA) to the National Coal Association (NCA), EPA and NCA apparently have differences about forecasts of SO_2 emissions form coal-fired power plants. Please provide a table showing the EPA and NCA projections and the assumptions adopted by both. Please explain how the assumptions may differ and the significance of the of the differences. Please indicate to what extent, if any, the recent reduction in the price of all and other market forces may affect these predictions. We are providing a copy of this enclosure to the Department of Energy (DOE) to comment on the forecasts. Please discuss the implications of these differences to the potential cost and emission reductions achieved by this bill.

Response:

Attachment 2A is an excerpt from a recent report by ICF, Inc. which summarizes the differences between EPA and NCA projections of future SO_2 emissions.

We have not yet performed an analysis using current low oil prices. The environmental implications of lower oil prices are not obvious because oil would displace lower-emitting gas as well as higher-emitting coal. Lower oil prices also could stimulate increased economic activity, resulting in higher overall electricity growth, and perhaps even increased coal use and emissions.

If one assumes that oil (and possibly gas) prices will remain very low for a prolonged period of years, this could affect both emissions and cost results we have estimated for H.R. 4567. It is possible that oil and gas could replace some coal burning in the base case projection. This would reduce base emissions and emission rates, thus requiring smaller reductions, at lower cost, to meet the required targets. Switching to oil and gas is also possible as a compliance strategy. With very low fuel prices, this could reduce compliance costs somewhat.

On the other hand, lower fuel prices could stimulate higher electricity demands and higher base case emissions. In this case, the implementation of H.R. 4567 might require larger reductions and higher costs than we have projected. Also, total emissions after implementation of the reductions would be higher because the emissions rate requirements would be applied to higher total fuel use.

Evaluating the net effect of all if these possible responses would require a complex analysis. We have asked ICF to conduct more detailed analysis of this issue which will be incorporated into their final report.

Question 2.b.

[You referenced a March 3 letter from EPA to National Coal Association and then asked us the following questions.]

What actions has EPA taken or can it take to prevent such shifts to higher sulfur coal? Please explain the term "sulfur premiums," the range of amounts of such premiums, and their impact. Can we expect such premiums under this legislation if a utility opts to shift to low sulfur coal or some mixture of such coal? Please discuss the difficulty caused by these shifts in determining compliance with the emission caps in the bill.

Response:

There is nothing that EPA can do to prevent a powerplant which had previously been emitting at a level well below its SIP limit from increasing its emissions, as long as it remains below its legally sanctioned ceiling. Under current law, a state would have to justify any SIP changes on an ambient basis. However, under a congressionally mandated acid rain control program, states could tighten SIP limits to prevent emissions creep.

"Sulfur premiums" are the price differentials between high and low sulfur coal. They are related to the cost differences between mining and transporting low vs. high sulfur coal, as well as the higher demand for low sulfur coal created by environmental regulations. Sulfur premiums vary greatly. They depend upon such factors as plant location, competition among coal suppliers, access to transportation facilities, and the stringency of environmental requirements. Because coal markets are currently depressed, current premiums range from $0-5 per ton.

Under our base case forecast, by the year 2000 when coal market conditions have significantly improved, premiums of $4-15 are created. According to our analysis of the default emission cap in the HR 4567, in the year 2000 sulfur premiums would be somewhat higher than in the base case, ranging from $5-25.

Any legislation which precipitates large amounts of coal switching will create sulfur premiums. The creation of such premiums complicates the achievement of emission caps for two reasons. First of all, incentives are created for uncontrolled plants to use cheaper, higher sulfur coals. Secondly, all other things being equal, lower prices of high sulfur coal relative to low sulfur coal will encourage the utilization of high-emitting plants relative to low-emitting plants. In developing plans to implement a control program, States will have to be careful that they take into account the changes in coal quality and utilization that would occur, to ensure that they will actually meet requirements of the program.

EXPERT REPORT OF
WALTER C. BARBER

DUKE ENERGY CORPORATION

AUGUST 15, 2002

/s/ Walter C Barber
Walter C. Barber

III. Conclusions and Opinions.

My job duties as Director of OAQPS required me to be fully aware of the statutory provisions and Congressional intent that both authorized and guided my office's activities. My understanding of the relevant statutory provisions derived from many sources, including my participation in discussions within USEPA and my personal review of the statute and accompanying legislative materials. My understanding of the topics under OAQPS's responsibility reflects the nature and type of understanding common among policy-level agency personnel who had senior responsibility for developing regulations authorized by USEPA's operating statutes. The ensuing discussion regarding the CAA, therefore, provides context to this report and my opinions regarding the development of the NSR programs and the manner in which USEPA is now interpreting these programs.

In 1970, Congress enacted the CAA to establish nationwide air quality standards to protect public health and welfare. These national ambient air quality standards specify the maximum permissible concentration of certain air pollutants in ambient air required to protect the public health with an adequate margin of safety. Congress directed the States to prepare implementation plans to control emissions of these pollutants to ensure attainment

and maintenance of the national ambient standards within their borders. Existing stationary emission sources, old or new, must comply with emission limits sufficiently stringent to ensure attainment and maintenance of these national ambient standards. The national ambient standards and the state implementation plans designed to achieve those standards are two of the cornerstones of air pollution control in the United States.

In addition, Congress enacted several CAA provisions directed primarily at new sources of air pollution. In 1970, Congress enacted the NSPS provisions of the CAA. These provisions required USEPA to promulgate performance standards for new sources in certain industrial categories to regulate the emission of air pollutants from such sources. In 1977, Congress amended the CAA to expand the NSPS program and to add specific PSD and NNSR programs. The PSD provisions of the CAA responded to concerns that air quality in areas meeting the national ambient standards should not be permitted to degrade significantly. The NNSR provisions addressed areas that had not yet demonstrated that they could attain the national ambient standards. As a general rule, the application of all three statutory provisions, NSPS, PSD and NNSR, require new sources to install pollution control technologies often more stringent than controls required for similar existing sources to which these programs do not apply. In enacting these NSR provisions, Congress clearly distinguished between existing and new stationary sources. The NSPS, PSD and NNSR statutory provisions do not apply to existing sources, unless an existing source is changed to such an extent that it is "modified" within the meaning of such provisions.

During the development and promulgation of the NSR programs, OAQPS was keenly aware of the Congressional distinction between new and existing sources. As Director of the office, I ensured that OAQPS developed regulations designed to carry out Congress' determination both that new sources should be required to install stringent, technology-based air pollution controls and that, unless an existing source was "modified," existing sources should not be required to install or be retrofitted with such air pollution controls. Consistent with the statutory principles and Congressional intent, OAQPS developed regulations providing that those existing sources would be addressed, if needed, through a state's regulation of existing sources under its state implementation plan.

As applied to the electrical utility industry, OAQPS developed regulations primarily addressing new sources. Existing sources (the vast majority of which at that time were coal-fired steam generating facilities) were required to be retrofitted with enhanced air pollution control devices only when those sources were changed to such an extent as to render them "modified," which was something that was expected to occur only rarely. Three of the critical bases for this mindset are as follows. First, as I have discussed above, OAQPS understood that Congress did not intend to develop regulations that would provide for extensive retrofitting of existing sources. Second, OAQPS believed that, in general, requiring existing electric generating power plants to be retrofitted with new control technologies would not be cost-effective. Finally, in developing regulations, OAQPS was always mindful of the country's increasing demand for energy, its vulnerability to foreign sources of energy, and the increasing role coal

was playing as a relatively affordable and available source of domestic energy.

When USEPA promulgated implementing regulations for the NSR programs, it addressed several activities at existing sources that it determined should not trigger the NSR programs. One set of these activities is routine maintenance, repair and replacement at an air pollution source. Given the relative newness of the PSD and NNSR regulations during my tenure as Director of OAQPS, most of our experience regarding what level of activity at an existing source would be considered a modification and trigger NSR came from the NSPS program.

During my tenure as Director of OAQPS, to trigger NSPS, the activity at the source had to be sufficient to increase the capacity of a source to emit air pollutants or to emit a new pollutant not previously emitted. If the source were engaged in activities necessary to maintain the plant's current operating conditions or return itself to its original operating capacity, OAQPS did not consider those activities to trigger NSPS. For example, if a plant, which operated at a 100-megawatt capacity when originally built, declined over time and needs to conduct repairs or replace parts to return to its original 100-megawatt operating capacity, absent extraordinary circumstances, OAQPS did not consider those activities to trigger NSPS.

Another activity that OAQPS generally would not consider to trigger NSPS was an increase in hours of operation at an existing plant. It was our belief that activities that allowed a source to operate more hours did not trigger NSPS unless those activities also increased the capacity of that source to emit pollutants. Thus, if a plant's

hours of operation decline because of problems associated with a key component, such as an economizer or a reheater, and if such components were replaced or repaired and the plant increased hours of operation thereafter, this would not trigger NSPS.

OAQPS carried over into the PSD and NNSR regulations the general mindset regarding the magnitude and scale needed to trigger a modification developed under the NSPS program and the specific NSPS definitional terms of "modification," "routine maintenance repair and replacement" and "increased hours of operation" and our interpretations thereof. Furthermore, as used in the PSD and NNSR programs, OAQPS gave these terms the same meaning and intent as in the NSPS program and believed that the same order of magnitude and scale needed to trigger NSPS would apply to the PSD and NNSR programs.

During my tenure as Director of OAQPS, it was both my own, and I believe USEPA's intention that relatively few existing coal-fired power plants would be brought within the NSR programs through the modification provisions. In fact, it was both our intent and expectation that very few existing power plants would be required to be retrofitted with new control technologies. If USEPA is now interpreting these regulations so that a significant number of existing power plants would trigger NSR and require retrofitting of controls, then I believe that such an interpretation is beyond the intent of the controlling statute and implementing regulations promulgated during my tenure.

I have reviewed the summary of a census of electric utility industry maintenance, repair and/or replacement

activities contained in Comments of The Utility Air Regulatory Group, filed on September 17, 2001 with USEPA in Docket No. A-2001-19 regarding the New Source Review 90 Day Review. If USEPA is now interpreting the NSR regulations so that maintenance, repair and replacement activities such as the commonplace activities listed in this summary, including replacement of key boiler components at existing power plants, typically would cause these plants to fall within the NSR programs and require retrofitting with updated control technologies, then I would be surprised at that interpretation and believe that such an interpretation would be inconsistent with the intent of the NSR programs as passed by Congress and as promulgated by USEPA.

Furthermore, I believe that applying the modification provision of the NSR programs in that way during my tenure at OAQPS would have found little, if any, support in USEPA or the Carter Administration in general. For example, the 1978 Electric Utility Steam Generating Units Background Information Document (July, 1978) confirms my view, and USEPA's view at the time, that the replacement of the pulverizer system of an existing coal-fired unit, a key component of a boiler, with a similar system, or replacement of component parts of the pulverizer system, would not be considered a modification (page 5-4.) Indeed, only a major redesign of key components of a steam generation system would cause a source to be evaluated under the modification regulations. In further support of this view, the background document states that there was little possibility that existing boilers would be subject to the modification and reconstruction provisions of the CAA (page 1-83).

Finally, it was neither mine nor USEPA's intention that the NSR programs would be used as a vehicle to require the vast majority of existing coal fired power plants to be retrofitted with updated control technologies. If USEPA were to find or be presented with new information regarding an underlying assumption used in establishing the NSR programs, or just wishes to change the policy decisions contained therein, then the appropriate course of action would be to return to the rulemaking process or even the authorizing legislation and seek amendments based on this new information or desire. In my opinion, it would be inappropriate to act on such new information or desires by, in effect, informally changing long standing regulations and advocating these changes through enforcement actions.

EXHIBIT 16

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR, NOISE AND RADIATION

Apr. 21, 1983

MEMORANDUM

SUBJECT: PSD Applicability Determination-
Southwestern Public Service Company

FROM: Director,
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

Acting Associate General Counsel
Air, Noise and Radiation Division

TO: Allyn M. Davis, Director
Air and Waste Management Division, Region VI

Paul Seals
Regional Counsel, Region VI

This is in response to your memorandum dated February 18, 1983 concerning the applicability of PSD to the Southwestern Public Service Company's (SPS) steam electric generating station in Amarillo, Texas. SPS operates a coal-fired steam generating unit subject to the NSPS requirements of 40 CFR 60 Subpart D. SPS is proposing to modify its existing air pollution control system which consists of two electrostatic precipitators (ESP) with 95 percent control efficiency of particulate matter followed by six wet scrubbers which remove enough of the remaining particulate matter to comply with the particulate matter emission standard of the NSPS. The

scrubbers also provide a significant effect on the SO_2 emissions by reducing their amounts by approximately 40 percent. These scrubbers, however, are not necessary in order for SPS to comply with the SO_2 requirements of the NSPS. The control alternative SPS has selected for this purpose is low sulfur coal.

The modification that SPS is proposing is the removal of the scrubbers and an upgrading of their ESP which will maintain their present level of compliance with the particulate matter NSPS. However, removal of these scrubbers will result in an approximate increase of 4400 tons per year of SO_2. The question you raise then is, does this modification of the control system constitute a major modification for the purposes of PSD?

Previously it has been determined that this change would not constitute a modification under the NSPS program. The NSPS regulations at 40 CFR 60.14(e) contain a list which exempts certain changes from consideration as modifications. Included in this list is the provision at 40 CFR 60.14(e)(5) which states:

> "The addition or use of any system or device whose primary function is the reduction of air pollutants except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial."

Under this provision it was determined that SPS' proposed modification would not be less environmentally beneficial for NSPS purposes since the change contemplated by SPS would still result in compliance with the NSPS for both particulate matter and SO_2.

The separate question of PSD applicability arises because the PSD modification provisions do not specifically contain an exemption such as that at §60.14(e)(5). After consultation with the Office of General Counsel, we both agree with the rationale presented by the Texas Air Control Board (TACB) in their January 21, 1983 letter to Dick Whittington. TACB believes that since the NSPS regulations provide an exemption from the modification provisions for replacement of control equipment, the PSD regulations must provide this exemption as well. This is because the Clean Air Act provides in Section 169(1)(c) that for PSD purposes the term modification shall be defined as that term is defined in Section 111(a) of the Act relating to NSPS. EPA has interpreted this to mean that for PSD purposes Congress intended the term modification to include all exemptions included in the NSPS regulations promulgated under Section 111 of the Act prior to the date of enactment of Section 169. See 43 FR 26396. The control equipment exemption was promulgated prior to Section 169. Therefore, the term modification in the PSD regulations inherently encompasses the control equipment exemption.

I wish to add, however, that just because it was determined that the change was not less environmentally beneficial under the NSPS program does not mean the same conclusion must be drawn with regard to PSD. Under the PSD program the concern is not solely the application of best technology, but also impacts on air quality from industrial growth. The Region and State must evaluate this situation to ensure there will be no adverse air quality impact before concluding that the control equipment replacement will not be less environmentally beneficial. If this determination can be made, the

SPS generating station in Amarillo may be exempted from PSD as a major modification.

If you have any additional questions or comments concerning this response, please contact Rich Biondi of SSCD at 382-2831 or Sara Schneeberg of OGC at 382-7730.

/s/ Edward E. Reich
Edward E. Reich

/s/ Wm. F. Pederson
William F. Pederson

cc: Peter Wyckoff
Mike Trutna
Tom Diggs

EXHIBIT 23

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF ENFORCEMENT

Jun. 24, 1981

Mr. Amasjit S. Gill
General Electric – Gas Turbine Division
One River Road
Schnectady, New York 12345

Dear Mr. Gill:

This is to respond to your letter of May 19, 1981, requesting a determination of the applicability of NSPS and PSD to stationary gas turbines converting from middle distillates to natural gas.

The information presented in your letter indicated that NO_x and So_2 emissions will decrease after the conversion to natural gas and hydrocarbons, CO and particulate emissions will either remain the same or decrease. As you correctly pointed out in your letter, the NSPS would only apply if there is an increase in emissions of a pollutant to which the standard applies. The NSPS for gas turbines applies only to NO_x and So_2 emissions. Since the conversion from middle distillate fuel to natural gas for the turbines in question will cause a decrease in NO_x and So_2 emissions, it is not considered a modification as defined in 40 CFR 60.14(a). The turbines however, could be subject to the NSPS if the conversion falls under the definition of reconstruction (See 40 CFR 60.15).

PSD review would apply to a proposed modification at an existing major stationary source if it would cause a

significant net increase in actual emissions of any regulated pollutant. In the case of the gas turbine conversions outlined in your letter, PSD applicability is determined by evaluating any change in emissions rates caused by the conversions. The data contained in your letter indicate that the emission rates after the conversion will either remain constant or decrease. Actual emissions could increase only if there is an increase in the production rate or hours of operation, both of which are specifically exempt from PSD review. (See 40 CFR 5221(b)(2)(iii)(f)). Therefore, since there will not be any increase in emission rates or any creditable increases in actual emissions, the conversion of the gas turbines will not be subject to PSD review.

If you have any questions concerning this determination please contact Janet Farelia of my staff at 202-755-2564.

Sincerely yours,

/s/ Edward E. Reich
Edward E. Reich, Director
Division of Stationery
Source Enforcement

cc: Peter Wyckoff
Mike Trutna

GENERAL [LOGO] ELECTRIC

GENERAL ELECTRIC COMPANY
ONE RIVER ROAD, SCHENECTADY,
NEW YORK 12345
Telephone
(518) 385-4131

GAS TURBINE
DIVISION
OPERATIONAL PLANNING

May 19, 1981

Copy: Don R. Goodwin, EPA
Research Triangle
Park, NC 27711

Mr. Edward Reich, Director
Division of Stationary Source Enforcement
Environmental Protection Agency
401 M Street, S.W.
Washington, D.C. 20460

Dear Mr. Reich:

Stationary Gas Turbines
Converting from Distillate to Natural Gas

The Economic Regulatory Administration of the Department of Energy grants temporary public interest exemptions, from the prohibitions of the Fuel Use Act of 1978, to burn natural gas where such use displaces the use of middle distillates, thereby decreasing our reliance on imported oil.

Existing gas turbines, which do not have built-in dual-fuel capability, must install new combustion hardware so that they can burn natural gas instead of middle distillates. The concern arises whether such a conversion would be calssified a "modification" or "major modification" and, therefore, subject the gas turbine to the New Source Performance Standards (NSPS) or a Prevention of Significant Deterioration (PSD) review.

MODIFIED

The definition of modification is provided in 40 *CFR* 60 as:

> 60.14 (a) "Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to any existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a *standard* applies shall be considered a modification within the meaning of Section III of the Act . . . "
>
> 60.2 "'Standard' means a standard of performance proposed or promulgated under this part."

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Hydrocarbons, carbon monoxide and particulates are specifically excluded from the NSPS promulgated on Sept. 10, 1979. Justification for the exclusion was provided in the Oct. 3, 1977 *Federal Register* on page 53783.

> "HC and CO emissions from stationary gas turbines operating at peak load are relatively low because the higher the percentage of peak load at which a turbine operates, the more efficient the combustion of the fuel. Gas turbines normally operate at 80 to 100 percent of peak load with HC emissions averaging less than 50 ppm and CO emissions averaging less than 500 ppm at 15 percent oxygen. HC and CO emissions from stationary gas turbines, therefore, were not selected for control by standards of performance."
>
> "Particulate emissions from stationary gas turbines depend on the ash content of the fuel and

are minimal. Consequently, particulate emissions from stationary gas turbines were not selected for control by standards of performance."

Since there is no standard for CO, unburned hydrocarbons and particulates under NSPS for stationary gas turbines, NSPS would not apply even if there was an increase in the emission rate of these three pollutants. As shown in the attached four tables, NO_x and SO_2 decrease, and CO, unburned hydrocarbons and particulates remain unchanged or decrease.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

PSD review would apply if the emissions increase by amounts greater than de minimis levels. De minimis levels, shown on page 52709 in the August 7, 1980 *Federal Register*, are:

	Tons/Year	Equivalent lbs/hour (8760 hours/year)
Carbon Monoxide	100	22.83
Nitrogen Oxides	40	9.13
Sulfur Ofoxide	40	9.13
Particulates	25	5.70
Volatile Organic Compounds	40	9.13

For those machines which are not restricted to a specific number of hours of operation per year by an enforceable permit condition, allowable emissions would be the hourly emission rate multiplied by 8760 hours per year. Then, for PSD review purposes, net emissions increases should be evaluated against these allowable emissions to see if de minimis levels are exceeded.

PG7101E

FUEL →		NATURAL GAS		DISTILLATE	
LOAD →		BASE	PEAK	BASE	PEAK
Output,	kW	74,400	80,500	72,900	78,800
Heat Rate (LHV),	Btu/kWH	10,690	10,640	10,790	10,750
Fuel Consump. (LHV) 10^6 Btu/hr		795.3	856.5	786.6	847.1
NOx as NO2,	lbs/hr	450	535	790	970
*SOx as SO2,	lbs/hr	0	0	254	275
Particulates,	lbs/hr	< 28	< 30	28	30
Hydrocarbons, (as CH_4),	lbs/hr	< 12	< 12	12	12
CO,	lbs/hr	< 21	< 21	21	21

*Distillate Fuel with 0.3% Sulfur by Weight,
Natural Gas Fuel Containing no Sulfur.

The results are based on field and combustion laboratory test data from the same or similar machines and combustion systems, correlated to provide a coherent body of emissions data. The data presented are for operation at ISO conditions.

PG7851

FUEL →		NATURAL GAS		DISTILLATE	
LOAD →		BASE	PEAK	BASE	PEAK
Output,	kW	61,300	67,700	60,000	66,300
Heat Rate (LHV),	Btu/kWH	11,000	10,920	11,130	11,030

Fuel Consump. (LHV) 10^6 Btu/hr		674.3	739.3	667.8	731.3
NOx as NO2,	lbs/hr	325	405	510	640
*SOx as SO2,	lbs/hr	0	0	216	237
Particulates,	lbs/hr	<24	<26	24	26
Hydrocarbons, (as CH_4),	lbs/hr	<11	<11	11	11
CO,	lbs/hr	<19	<19	19	19

*Distillate Fuel with 0.3% Sulfur by Weight,
Natural Gas Fuel Containing no Sulfur.

The results are based on field and combustion laboratory test data from the same or similar machines and combustion systems, correlated to provide a coherent body of emissions data. The data presented are for operation at ISO conditions.

PG5341P

FUEL →		NATURAL GAS		DISTILLATE	
LOAD →		BASE	PEAK	BASE	PEAK
Output,	kW	24,620	26,600	24,110	26,050
Heat Rate (LHV),	Btu/kWH	12,300	12,200	12,450	12,340
Fuel Consump. (LHV) 10^6 Btu/hr		302.8	324.5	300.2	321.5
NOx as NO2,	lbs/hr	140	155	200	225
*SOx as SO2,	lbs/hr	0	0	97	104
Particulates,	lbs/hr	< 11	< 11	11	11
Hydrocarbons, (as CH_4),	lbs/hr	< 5	< 5	5	5
CO,	lbs/hr	< 10	< 10	10	10

*Distillate Fuel with 0.3% Sulfur by Weight,
Natural Gas Fuel Containing no Sulfur.

The results are based on field and combustion laboratory test data from the same or similar machines and combustion systems, correlated to provide a coherent body of emissions data. The data presented are for operation at ISO conditions.

PG6441A

FUEL →		NATURAL GAS		DISTILLATE	
LOAD →		BASE	PEAK	BASE	PEAK
Output,	kW	31,750	34,750	31,100	34,000
Heat Rate (LHV),	Btu/kWH	11,280	11,210	11,380	11,310
Fuel Consump. (LHV) 10^6 Btu/hr		358.1	389.5	353.9	384.5
NOx as NO2,	lbs/hr	185	220	325	385
*SOx as SO2,	lbs/hr	0	0	115	125
Particulates,	lbs/hr	< 13	< 14	13	14
Hydrocarbons, (as CH_4),	lbs/hr	< 6	< 6	6	6
CO,	lbs/hr	< 11	< 11	11	11

*Distillate Fuel with 0.3% Sulfur by Weight,
Natural Gas Fuel Containing no Sulfur.

The results are based on field and combustion laboratory test data from the same or similar machines and combustion systems, correlated to provide a coherent body of emissions data. The data presented are for operation at ISO conditions.

EXHIBIT 24

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF ENFORCEMENT

Jan. 22, 1981

MEMORANDUM

SUBJECT: PSD Applicability

FROM: Director
Division of Stationary Source Enforcement

TO: Charles Whitmore, Chief
Technical Analysis Section, Region VII

This is in response to your memo of December 4, 1980, in which you requested a PSD applicability determination for Cargill Inc.'s proposed ethanol plant in Eddyville, Iowa.

The proposed plant is to be located in a designated attainment area and will consist in part of wet-milling and ethanol facilities (collectively, the "ethanol plant"). Steam and electricity for the plant are to be generated by an on-site existing power plant, which is to be converted into a co-generation unit. The addition of the ethanol plant will cause a large increase in the hours of operation of the power plant and a fuel switch to burn coal exclusively.

I would like to mention first that the project may be exempt from PSD review through a "grandfather" exemption if the state air permit for the project was issued before August 7, 1980, the project would not have been subject to

the 1978 PSD regulations, as stayed, and certain other conditions are met. (See 40 CFR 52.21 (i)(4)(V)).

If the grandfather exemption does not apply the addition of the ethanol plant should be considered a modification to an existing major stationary source. In order to determine if the modification is major and subject to preconstruction PSD review, it is first necessary to determine if there will be a significant net emissions increase from the modification itself. EPA is interpreting the term "net emissions increase" as any *significant* increase in actual emissions from a physical change or change in the method of operation at a stationary source and any other creditable contemporaneous increases or decreases in actual emissions. A conforming amendment to this effect will be published in the *Federal Register*. In this case there is an expected increase at the ethanol plant of approximately 15 TPY of TSP, 11 TPY of SO_2 and less than 40 TPY VOC. All of these emission rates are de minimus, (See 40 CFR 52.21(b)(23)) and therefore this modification would not be subject to PSD review. Regardless of whether or not this is determined to be a modification any increase in emission will consume increment provided the baseline has been triggered.

It is also important to note that, in the absence of any SIP or permit limitations, neither the increase in emissions from the switch to burn coal exclusively nor the increase in hours of operation at the power plant would be considered a modification (See 40 CFR 52.21(b)(2)(iii)(*e*) and (*f*)).

This determination has been made with the concurrence of the Office of Air Quality Planning and Standards and the Office of General Counsel. If you have any questions

regarding this memo, please contact Janet Littlejohn of my staff at 755-2564.

/s/ Edward E. Reich
Edward E. Reich

cc: Peter Wyckoff, OGC
Mike Trutna, OAQPS
Darryl Tyler, OAQPS

EXHIBIT 29

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20450

Oct. 14, 1988

THE ADMINISTRATOR

Mr. John W. Boston
Vice President
Wisconsin Electric Power Company
Post Office Box 2046
Milwaukee, Wisconsin 52301

Dear Mr. Boston:

As you requested in our meeting on September 15, 1988, I have made final determinations regarding the applicability of the Clean Air Act's New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements to the proposed life extension project at the Port Washington steam electric generating station, which is owned and operated by Wisconsin Electric Power Company (WEPCO). For the reasons discussed below, I have determined that, as proposed, the renovations at Port Washington are subject to both PSD and NSPS requirements. However, EPA remains willing to work with you regarding methods of compliance. As we have discussed, one alternative would be to reconfigure the project such that no emissions increases would occur. My staff is ready to meet with you to discuss these matters at any time.

I. BACKGROUND

On September 12, 1988, David Kee, Director Air and Radiation Division, EPA Region V, wrote you regarding PSD and NSPS coverage of the Port Washington renovations. Enclosed with that letter was a memorandum dated September 9, 1988 from Don R. Clay, Acting Assistant Administrator, addressing the background of the Port Washington project, and analyzing at some length the relevant interpretative issues. For purposes of brevity, I will not repeat that material here, but rather incorporate it by reference.

The September documents concluded that the life extension project, as proposed, *likely* would be subject to PSD and NSPS requirements. However, EPA also stated that final applicability determinations could not be provided at that time in the absence of certain factual information. In our subsequent meeting you requested that EPA furnish final determinations, and agreed to provide the necessary additional information. You also asked EPA to reconsider certain of the conclusions in Don Clay's memorandum. These matters are discussed below.

II. FINAL DETERMINATIONS

Your staff has responded to our requests for additional information, and I want to thank you for WEPCO's continued cooperation in doing so. Based on this, and the other information in EPA's files, I now make the following final determinations:

(1) The life extension project, as proposed, will render WEPCO's Port Washington plant subject to the PSD requirements of Part C of the Clean Air Act as a

major modification within the meaning of the Act and the EPA regulations at 40 C.F.R. § 52.21.

(2) The proposed life extension project will render each of the five steam generating units at the Port Washington plant subject to the NSPS requirements of section 111 of the Clean Air Act as modification within the meaning of the Act and the EPA regulations at 40 C.F.R. Part 60.

In reconsidering the memorandum and letter of September 9 and 12, I have taken a careful look at the issues you raised in our meeting: whether the renovations are routine; whether EPA has treated similar projects in a different fashion; and whether there would be an emissions increase due to a physical or operational change. However, I find no reason to depart from the reasoning of the September documents. Accordingly, I conclude that WEPCO's life extension project, if carried out as proposed, will involve a substantial and non-routine renewal of the Port Washington facilities that will significantly increase both hourly maximum and annual emissions of air pollutants.

Specifically, regarding the nature of the proposed work at Port Washington, I find that these renovations constitute physical changes for PSD purposes within the meaning of 40 C.F.R. § 52.21(b)(2)(i), and physical and operational changes for NSPS purposes within the meaning of 40 C.F.R. § 60.14(a). I find further that these changes do not come within the PSD and NSPS exclusions for routine maintenance, repair, and replacement, nor the exclusions for increases in production rate or hours of operation. (See 40 C.F.R. §§ 52.21(b)(2)(iii) and 60.14(e)).

Regarding the emissions changes from the life extension project, based upon the emissions data and certain factual assertions submitted by WEPCO, I find that the Port Washington renovations will result in a significant net increase in emissions of several pollutants for PSD purposes within the meaning of 40 C.F.R. § 52.21(b)(2)(i), (b)(3), and (b)(21). I find further that the renovations will result in an increase in the emission rate of several pollutants at each of units 1-5 for NSPS purposes within the meaning of 40 C.F.R. § 60.14(a) and (b).

Enclosures A and B detail the emissions changes underlying these findings for PSD and NSPS purposes. As indicated above, EPA's calculations and determinations are based on data supplied by WEPCO. We will use the data in Enclosures A and B in the event you would like to work with us to establish an acceptable arrangement for satisfying PSD and NSPS requirements through the addition or enhancement of pollution control equipment, physical capacity restrictions, or, in the case of PSD, federally enforceable limitations on potential emissions.

III. DISCUSSION

As you requested, I have reconsidered the question of whether the physical and operational changes at Port Washington are routine, whether applying PSD and NSPS here would be inequitable in light of EPA's past treatment of renovation projects, and whether the renovations will result in emissions increases. These matters are addressed below, as is EPA's reasoning with respect to the baselines for calculating the PSD and NSPS emissions increases reflected in Enclosures A and B.

Regarding the question of routineness, the renovations involve the replacement of steam drums, air heaters, and other major components that are integral to the continued operation of the source. The work will not simply maintain the facilities in their current state, but rather will significantly enhance their present efficiency and capacity, and substantially extend their useful economic life. In addition, the work called for here is rarely, if ever, performed. Moreover, this work is costly, both in relative and absolute terms. Based on these and other factors, I reaffirm Don Clay's findings on the non-routine character of the Port Washington changes. The September 9 memorandum contains a complete discussion of EPA's reasoning on this issue.

On the related equity question, I find no inconsistency here with EPA's prior determinations regarding routine and non-routine changes. I note initially that PSD and NSPS applicability determinations are made on a case-by-case basis. Thus, it is very difficult to analogize to other projects, which almost inevitably present significant factual differences. Nevertheless, my staff has reviewed the additional material you submitted on September 19, and September 27, 1988 regarding certain other renovation projects, and has informally surveyed EPA Regional Offices and state agencies.

I have concluded that none of the four steam drum replacements identified in your September 19 submission are sufficiently similar to the Port Washington project to support determinations of nonapplicability in this matter. The Carolina Power and Light case involved a faulty steam drum replaced prior to the initial start-up of a new unit, and would not have increased emissions for PSD or NSPS purposes. The Great Western Sugar example did not

involve a utility boiler, and was too small to be affected by NSPS. The Ashland Oil facility was not at a utility, involved a waste heat boiler that was not fossil-fuel fired, and hence, was not an emissions unit subject to PSD or NSPS. The Algoma Steel Co. facility was not a utility boiler, and not located in the United States.

In addition, the informal survey conducted by the Office of Air and Radiation disclosed no closely analogous cases that were ever reviewed by EPA headquarters for purposes of PSD or NSPS applicability. In particular, EPA found no examples of steam drum replacement at aged electric generating facilities. Moreover, EPA could find no examples in which the Agency had analyzed and issued an applicability determination for a "life extension project" for any category of major source. Regarding the four utility projects identified in your September 27 submission, I note that they do not involve steam drum replacement. In addition, permit applications were not submitted to the state agencies for the Duke Power and Texas Utilities projects you cite. Consequently, they were not reviewed by any air pollution control agency. The Cincinnati Gas and Electric project was reviewed by the state, but not EPA. The state determined, and EPA Region II concurred, that the Hydraco Enterprises project was not subject to PSD based on a net decrease in emissions of all pollutants. Our informal survey and review of the projects you identified reveal that major construction activities undertaken by utilities that may be subject to Clean Air Act requirements have not been brought to the attention of EPA. The Agency is considering what steps, may be necessary to address this situation.

EPA has discovered only two state agency determinations addressing life extension questions in a manner

possibly inconsistent with EPA's analysis of the Port Washington project. These instances, which apparently were not brought to EPA's attention prior to the states' determination, do not create an inequity that would justify a different conclusion by EPA in this case.

As to the question of emissions increases at Port Washington, I believe that EPA has properly interpreted the PSD and NSPS regulations as applying to increases in emissions due to increases in hours of operation or production rate, where, as here, such operational or production increases are closely related to physical or operational changes. A contrary interpretation would allow even massive emissions increases stemming from significant new capital investment – as distinguished from routine fluctuations in the business cycle – to escape scrutiny under the Clean Air Act simply because the new investment did not involve an inherently more polluting production process. I do not believe that Congress intended such a result.

I would like to point out that the figures on emissions increases in Enclosures A and B reflect my conclusions regarding the proper points in time from which to calculate emissions changes. For PSD, I have determined under 40 C.F.R. § 52.21(b)(21)(ii) that the two-year period of 1983 and 1984 – prior to the source curtailments due to discovery of cracks in the rear steam drums – are more representative of normal source operations than the most recent two-year period. This conclusion is appropriate in light of WEPCO's historical operations.

As to NSPS, there is no "representative emissions" concept under that program. Rather, under the circumstances presented by this case, the baseline emission rates

for units 1-5 are determined by hourly maximum capacity just prior to the renovations. At this time, EPA is relying on the actual operating data you submitted to determine current maximum capacity. Although EPA is certainly open to further discussion on this point, the information contained in your September 27 and October 11, 1988 submissions is inadequate to support WEPCO's assertions that higher-than-actual capacities could be achieved on an economically sustainable basis. For example, you indicate that operation at higher levels at units 1-4 "could increase equipment deterioration thus causing further damage." Regarding Unit 5, you state that "safety concerns" dictated the decision to shut down that unit. Based on this information, we are unable to rely on WEPCO's statements as to maximum "achievable' capacity in determining the emissions changes at each of these units. Thus, for example, in the case of unit 5, the current capacity must be regarded as zero.

IV. CONCLUSION

In adopting the PSD and NSPS programs, Congress intended to address the type of long-term capital investments in pollution-emitting facilities at issue in the Port Washington life extension project. Thus, as proposed, these renovations would be subject to the requirements of both programs. However, as indicated above, my staff remains ready to work closely with WEPCO to discuss specific pollution control equipment and permitting measures that would minimize the cost to WEPCO of complying with the requirements of the Clean Air Act. I have asked Don Clay to work with you in seeking a final resolution of the compliance issues by December 1.

Again, thank you for your cooperation is this matter.

Sincerely,

/s/ Lee M. Thomas
Lee M. Thomas

Enclosures

cc: Senator Robert W. Kasten, Jr.
Representative F. James Sensenbrenner, Jr.
Don Clay, EPA (ANR-445)
David Kee, Air & Radiation Div., Region V

Enclosure A

PSD Applicability

Port Washington Power Plant Renovation Project

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Potential Emissions (2)	Net Emissions Increase	PSD Level	Subject to, PSD Review
Total suspended particulate	170	283 (3)	108	25	yes
Sulfur dioxide	24,234	52,621 (3)	28,385	40	yes
Nitrogen oxides	2,991	8,201	5,210	40	yes
Carbon monoxide	144	397	253	100	yes
Hydrocarbon	17	47	30	40	no
Beryllium	0.0016	0.005	0.0034	0.0004	yes
Fluorides	38	98	60	3	yes

NOTE: PSD applicability for the other PSD regulated pollutants listed at 40 CFR Section 52.21(b)(23)(i) and (ii) has not been determined at this time.

1) Average emissions for two-year period defined by calendar years 1983 and 1984.

2) As calculated by WEPCO based on 1992 coal type, actual emissions after ESP, and an annual capacity utilization factor of 90%.

3) An EPA estimate of potential emissions, based on existing federally enforceable limits (i.e., applicable SIP), may be higher. The indicated PSD applicability determination would, however, not change.

Enclosure B

NSPS Applicability
Port Washington Power Plant Renovation Project

FULL LOAD EMISSIONS AT CURRENT CAPACITY (BEFORE RENOVATION)

	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO_2 (LBS/HR)	1417	1828	2043	1580	-0-
PM (LBS/HR)	15	16	12	12	-0-
NOx (LBS/HR)	480	352	289	221	-0-

FULL LOAD EMISSIONS AT FUTURE CAPACITY (AFTER RENOVATION)

	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO_2 (LBS/HR)	2046	2037	2088	2269	2695
PM (LBS/HR)	16	16	12	17	15
NOx (LBS/HR)	696	392	297	316	369

SUBJECT TO NSPS
(AFTER RENOVATION)

	UNIT-1	UNIT-2	UNIT-3	UNIT-4	UNIT-5
SO_2 (LBS/HR)	YES (a)	YES (a)	YES (a)	YES (a)	YES
PM (LBS/HR)	YES (b)	NO	NO	YES (b)	YES
NOx (LBS/HR)	YES (c)	YES (c)	YES (c)	YES (c)	YES (c)

Notes:

(a) With less add-on control than NSPS requirement, emissions (lb/hr) would not increase and NSPS would not apply.

(b) Because of planned ESP upgrade, PM emissions (lb/MM Btu) after renovation are expected to be less than NSPS requirement. However, NSPS would require CEMS for opacity.

(c) Because arch-fired boilers are used at Port Washington, current NOx emissions (lb/MM Btu) are expected to be less than NSPS requirements. However, NSPS would require a CEMS for NOx.

EXHIBIT 31

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION V

DATE: MAR. 25, 1988

SUBJECT: PSD Applicability for a Power Plant Life Extension Project

FROM: David Kee, Director
Air and Radiation Division

TO: Gerald A. Emison, Director
Office of Air Quality Planning and Standards

I am requesting guidance on a Prevention of Significant Deterioration (PSD) applicability determination. Wisconsin Electric Power Company (WEPCO) intends to renovate its Port Washington plant. The Wisconsin Department of Natural Resources (WDNR) has asked if the United States Environmental Protection Agency (USEPA) considers these renovations subject to the requirements for a "major modification" in the Federal PSD regulations in 40 CFR 52.21. A physical change or change in the method of operation of a major stationary source is subject to PSD. However, an increase in the hours of operation or the production rate is not considered a physical change or change in the method of operation [see 40 CFR 52.21(b)(2)(iii)(f)]. WEPCO believes the renovation project is merely an increase in production which is not subject to PSD regulations.

WEPCO operates five coal-fired boilers at the Port Washington plant. One boiler has been shut down for 3 years due to a cracked steam drum. The others have not been able to operate at full capacity due to degradation. Some of

the boilers have suffered more degradation than others as illustrated below:

	Generator Nameplate (megawatts)	1986 Summer Capability* (megawatts)	Year of Initial operation
Unit 1	80	49.0	1935
Unit 2	80	69.0	1943
Unit 3	80	78.0	1948
Unit 4	80	57.0	1949
Unit 5	80	75.0	1950

*From *Inventory of Power Plants in the United States 1986.* Energy Information Administration

The renovations are intended to restore the boilers to their nameplate capacities and to allow them to operate until 2010. Plantwide capacity would increase about 40 percent above current levels to 400 megawatts. Net emission increases of sulfur dioxide, particulate matter, and possibly other pollutants would be "significant." Capital expenditures will be required to restore the lost capacity because major boiler components will be replaced.

We are requesting concurrence with our determination that the WEPCO renovations are not exempt from PSD regulations under the provisions of 40 CFR 52.21(b)(2)(iii)(f). We consider this exemption to be only for increases up to the production rate that the source can operate at without altering equipment. In other words, an increase in production rate is exempt but a renovation that increases the production rate is not even though the renovation restores lost capacity.

Although the Port Washington plant may have been able to operate at 400 megawatts in the past, degradation has caused operational limitations that have restricted their

potential to emit. Our understanding is that an increase in actual emissions up to the potential to emit would be exempt under 40 CFR 52.21(b)(2)(iii)(f) but an increase in the potential to emit would not.

I have attached letters from Mr. Dale Ziege of WDNR dated November 9, 1987, and February 5, 1988, and from Mr. Mark Steinberg of WEPCO dated March 17, 1988. These letters comprise the State and company's request for an applicability determination.

We request your consideration of this applicability issue because boiler life extension projects appear to be on the increase nationwide and your determination here may impact numerous other projects. If you have any questions, please contact me or Bill MacDowell of my staff at FTS 886-6043.

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA
Civil Action No. 1:00 CV 1262

UNITED STATES OF AMERICA,
Plaintiff,
v.
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP
Plaintiff-Intervenors
v.
DUKE ENERGY CORPORATION
Defendant.

VIDEOTAPED I –
DEPOSITION OF WALTER STEVENSON
(Taken on behalf of the Defendant)
Durham, North Carolina
September 10, 2002

* * *

[42] [Q.] . . . Can you tell us whether you put together this Exhibit 175 before May 10, 1989?

A. Do you have that particular list with you so I can be sure? I believe I know what you're referring to. I just want to be sure I don't misstate.

MR. BECKHARD: While you're looking for that, can I ask for a short break? Comfort break.

VIDEOGRAPHER: We're off the record at 1:15.

VIDEOGRAPHER: We are on the record at 1:24.

BY MR. COTTINGHAM:

Q. Mr. Stevenson, before we took a break you said you wanted to look at what we call the Farmer memorandum which we looked at a number of times in other depositions. It is Exhibit 121 and 177. And I was asking you specifically about whether your list that you put together that's Exhibit 175 you put together before or after Mr. Farmer's memorandum dated May 10, 1989 which has an Attachment 3, a list of potential utility boiler life extension projects?

A. My list would have been put together prior to this list.

Q. So okay. Let's go back to your list, Exhibit 175 which is entitled "Known/Suspected Utility Life Extension/ Repowering Projects." When you use the term "life extension" on that list, first on the title and in the column type where [43] you use it, at least nine times, what did you mean by that, by life extension?

A. In the title or in the type?

Q. Either way, both.

A. The "type" is what the magazine article or whoever I read this, the term they used. I had no idea of what it necessarily meant. To the extent it was so common I just picked up whatever the most common and typed this up as just a working list. But again, that's why these terms – I just listed whatever was in the particular article subject.

Q. What did you mean in the title?

A. Up top it says "known/suspected/utility life extension repowering." What all that would mean come sometime in the future, I don't know for sure what they were even, the projects. This was the terminology used in these various articles I ran across. I don't know what they necessarily mean.

Q. And you didn't know what it meant when you wrote it at the top or typed it at the top of this document?

A. No. It was some of the more common terms. I think you see "life extension" "repowering" probably the two most common terms used in these articles so I just put it in there. I just typed this up.

Q. Why did you put this together?

A. Just working on projects over many years it just [44] seemed if the WEPCO determination had come up, it seemed like at some point somebody was going to ask should a study be done or how common it was. And to the extent I was running across these as I read things, I just typed up a list. I figured sometime in the future somebody could use it for something; but it was no particular, nobody asked me to put it together or anything. It was just a list I put together for efficiency.

Q. And you think you put it together sometime between September of 1988 when you and Sallie Harmon did the survey on life extension and May of 1989 when Mr. Farmer wrote his memorandum?

A. Yeah.

Q. What was happening during that time that related to life extension that would cause you to put together this memorandum?

A. Well, the sequence of events were that a determination was to be made on WEPCO, they made an application, they – so Sallie and I did a very quick survey to see if any determinations had been requested before and so forth. We continued to have discussions and meetings with WEPCO. They continued to submit data. We'd evaluate it and look at it in context of the NSPS program, and along that process reading these articles, like I say, these names started appearing. I put a list together. Ultimately the [45] Court made the decision all the briefs were filed and everything and the litigation was determined, the determination was made first, and then the litigation occurred. And then after the NSPS decision was completed, which again was one, that was that. We just went on to other projects.

Q. What did you do with this Exhibit 175 list after you put it together?

MR. BECKHARD: Objection. Outside the scope. You may answer in your personal capacity.

THE WITNESS: It just was put in my files, you know the WEPCO folder, just put it in there. Nobody particularly asked for it, but whether it was circulated I'd have to speculate, you know, somebody ask me for a copy about WEPCO. Nobody particularly asked me for this and it wasn't intentionally distributed to anybody. It just went in my files. We share a lot of data in our groups so everybody is pretty much aware of what was going on.

Q. Other people in your group were probably aware that you put together this list?

A. I have to speculate. It wouldn't surprise me either way. I don't remember distributing it to anybody. Don't remember anybody asking for it. I would expect, yeah.

* * *

EXHIBIT 33

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

Jun. 8, 1990

Mr. John Boston
President
Wisconsin Electric Power Company
Post Office Box 2046
Milwaukee, Wisconsin 52301

Dear Mr. Boston:

On January 19, 1990, the United States Court of Appeals for the Seventh Circuit in *Wisconsin Electric Power Co. v. Reilly*, Nos. 88-3264 and 89-1339, issued its decision regarding a challenge by Wisconsin Electric Power Company (WEPCO) to two final determinations issued by the Environmental Protection Agency (EPA). In these determinations, EPA concluded that WEPCO's proposed renovations to its Port Washington power plant would be subject to new source performance standards (NEPS) and prevention of significant deterioration (PSD) requirements.

In its decision, the court upheld all but one of the positions advanced by EPA in the NSPS and PSD applicability the issue of whether the "actual-to-potential" method – referred to by the court as the "potential to emit concept" – should be used to calculate emissions increases for PSD purposes in this case. Consequently, the Seventh Circuit vacated and remanded the PSD determination to EPA for further action consistent with the court's decision.

As you know, EPA decided to acquiesce in the court's holding rather than seek rehearing. This letter constitutes EPA's revised PSD applicability determination in responses to the court's remand order.

The Agency believes that the court's principal instruction – that EPA consider past operating conditions at the plant when addressing modifications that involve "like-kind replacements" – can be reasonably accommodated within the present regulatory framework without further litigation in this case. The net result of the court's ruling is the recognition of a subcategory of "like-kind replacements" under the "major modification" definition of EPA's new source review provisions.

As explained below, EPA will employ an "actual-to-actual" method to calculate emissions increases for WEPCO's proposed renovations to its Port Washington power plant. The outcome in this case is that WEPCO will not be subject to PSD review for sulfur dioxide (SO_2), particulate matter (PM), carbon monoxide, or hydrocarbons. However, there will be a significant net increase in actual emissions of nitrogen oxides (NOx), and WEPCO must obtain a PSD permit for that pollutant.

I. BACKGROUND

A. Factual Background.

The WEPCO owns and operates five coal-fired, steam-generating units at its Port Washington facility near Milwaukee. All units had an original design capacity of 80 megawatts when they were placed in service between 1935 and 1950. However, due to age-related deterioration and loss of efficiency, both the physical capability and actual utilization of the plant have declined over time. Unit 5 was

shut down completely due to a cracked rear steam drum. Consequently, by 1987, WEPCO was faced with removing the units from service as they reached their planned retirement dates beginning in the early 1990's, unless it undertook a costly "life extension" program to restore the physical and economic viability of the units and extend their useful life for approximately 20 years. The WEPCO proposed such a life extension to include replacement of the steam drums, air heaters, and other major capital improvements totaling over $80 million. It should be noted that this program is not a pollution control project (i.e., it is not intended to add on or improve pollution control systems even though modest improvements to the particulate matter control devices are a part of the program).

In a series of applicability determinations in 1988 and 1989, EPA ruled that the renovations planned under WEPCO'S life extension program would constitute a "modification" for purposes of the NSPS provisions of the Clean Air Act (Act), and a "major modification" under the PSD provisions of the Act. Thus, WEPCO would have had to install some level of control equipment or physical capacity restriction to avoid NSPS coverage for three of the five units proposed to be renovated. As to PSD, the company would have had to accept operational restrictions or lower emissions rates to "net out" of review. Regarding SO_2, for example, WEPCO could have almost doubled its projected level of future operations without triggering PSD review. However, WEPCO did not want to be constrained by new source requirements, and so sought review in the Seventh Circuit Court of Appeals.

B. The Court's Decision.

1. Physical Change.

The court unequivocally agreed with EPA that the replacement of steam drums, air heaters, and other major components was a nonroutine "physical change," and thus met the first of two tests for a modification under NSPS and PSD. The Agency found that the renovations proposed by WEPCO were exactly the type of industrial changes that were meant to be addressed by the NSPS and PSD progress. In upholding EPA's finding that a physical change would occur, the court strongly endorsed EPA's reading of the basic congressional intent in adopting the modification provisions of the NSPS and PSD programs, because to rule otherwise "would open vistas of indefinite immunity from the provisions of NSPS and PSD" (slip op. at 11). The court also relied on the reasonableness of EPA's consideration of the magnitude, purpose, frequency, and cost of the work in upholding EPA's finding that the renovations are not "routine" (slip op. at 14-18). In addition, the court rejected WEPCO's argument that the renovations could not be deemed a modification for NSPS purposes because they did not constitute a "reconstruction" under 40 CFR 60.15 (slip op. at 18-20).

2. NSPS Emissions Increase.

The court upheld EPA'S decision that there would be an increase in hourly emissions at three of the units, and thus for those three units, WEPCO met the second test for NSPS applicability. The Agency had argued that the regulations require NSPS emissions increases to be determined by comparing the current (pre-change) hourly emissions capacity of each affected facility with the post-renovation hourly

emissions capacity of each unit. The Seventh Circuit agreed, and rejected WEPCO's argument that original design capacity or past "representative" capacity no longer achievable at the plant should be used for the baseline emissions rate (slip op. at 20-25).

3. PSD Emissions Increase.

The regulatory preamble to the PSD regulations provides that the set of emissions units that have "not begun normal operations" includes both "new or modified" units (45 FR 52676, 52677, 52718) (1980). Consequently, EPA used the "actual-to-potential" calculus in evaluating WEPCO's life extension project. The court rejected this methodology in the case of WEPCO's "like-kind replacement," asserting that EPA's reasoning was circular (slip op. at 28). [In addition, the court held (slip op. at 27 n.11) that the exemption in 40 CFR 52.21(b)(2)(iii)(f) for emissions increases due to expanded operations did not apply because WEPCO's increased operations were directly tied to the life extension project.] Instead, the court ruled that EPA should recalculate post-change emissions considering past operating conditions where it is possible to make a more realistic assessment of future emissions (slip op. at 29-31). Alternatively, the court stated that EPA could conduct new rulemaking to explicitly apply the "actual-to-potential" calculus to "like-kind replacements" (slip op. at 30).

II. THE WEPCO DECISION IN THE CONTEXT OF THE PSD PROVISIONS

The Seventh Circuit held that EPA could not wholly disregard past operating history and automatically apply

the actual-to-potential methodology for determining PSD applicability to WEPCO's "like-kind replacements." In describing the WEPCO changes as "like-kind replacements" and limiting its decision to such changes, the court did not dispute the correctness of EPA's application of the actual-to-potential test to the full spectrum of new and modified sources not covered by this subcategory of change. The recent decision in *Puerto Rican Cement Co. v. EPA*, 889 F.2d 292 (1st Cir. 1989), explicitly upheld EPA's position that the actual-to-potential concept should be applied to "modified" emissions units. The First Circuit case involved the modernization and reconfiguration of existing emissions units [see 889 F.2d at 293 (company planned to "convert kiln No. 6 from a 'wet' to a 'dry' cement-making process, and to combine that with Kiln No. 3")]. A key issue was whether EPA properly held that the "modified" units had "not begun normal operation" and therefore the actual-to-potential concept applied in calculating emissions increases. The First Circuit affirmed EPA's position that the actual-to-potential concept should be applied to the company's "modified" units. *Puerto Rican Cement*, 889 F.2d at 297. Consequently, the court found that both the language and expressed purpose of the regulations indicate that EPA applied the regulations properly in using the actual-to-potential test for a proposed modification. The Seventh Circuit in *WEPCO* did not dispute the correctness of EPA's application of the actual-to-potential test to the full spectrum of changes not covered by the subcategory of changes (like-kind replacements) created by the court.[1] Therefore, in the case of

[1] EPA will leave to future case by case applicability determinations what is a "like-kind replacement." But for guidance of the parties, EPA presently considers that only for projects that are genuine "like-kind

(Continued on following page)

nonroutine physical or operational changes at an existing major source which are not specifically "like-kind replacements" in nature, EPA will continue to apply the actual-to-potential test for PSD applicability purposes.

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replacements" can future emissions projections be calculated using "estimated future actual emissions" in lieu of potential to exit. EPA does not consider "like-kind replacements" to mean the entire (or reconstruction) of an existing emissions unit with an identical new one or one similar in design or function. Rather, EPA considers "like-kind replacements" to encompass the replacement of components. Under this interpretation of the term, new components that perform essentially the same function as old ones will be viewed as "like-kind replacements." In addition, even if the design or purpose of a new component is identical to that of an old one, if the new component is part of a project that will fundamentally change the production process at an existing stationary source, this would be beyond the scope of a "like-kind replacement." Under either of those circumstances, it would be unreasonable to rely on premodification usage patterns to estimate future levels of capacity utilization. Instead, in such cases, EPA believes that it is reasonable to assume that in the absence of federally-enforceable limits on hours of operation or production rates, the new components may result in a substantial increase over historical levels of utilization of the emissions unit following modification [see *Puerto Rican Cement*, *supra*, 889 F.2d at 297 ("a firm's decision to introduce new, more efficient machinery may lead the firm to decide to increase the level of production")] and will compare pre-modification actual emissions to post-modification potential emissions. In addition to this circumstance, there are cases in which sources that undergo changes that qualify as add-on control systems would, under certain circumstances, be exempt from new source review. *See* Letter to Timothy J. Method, Assistant Commissioner, Indiana Department of Environmental Management, from David Kee, EPA Region V, January 30, 1990.

III. THE AGENCY'S RESPONSE TO THE COURT'S REMAND ORDER

A. The PSD Baseline Emissions.

Determining the "baseline" level of actual emissions before a physical or operational change is a necessary first step to determine if emissions increase as a result of the physical change. The Agency's regulations define the baseline for PSD purposes, as follows:

> In general, actual emissions as of a particular date shall equal the average rate, in tons-per-year (tpy), at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and *which is representative of normal source operation.* The Administrator *shall* allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period [see 40 CFR 52.21(b)(21)(ii)].

The purpose of the definition is to establish a baseline that is "representative" of "normal" source operations prior to the change. The Agency historically has followed a presumption that the most recent 2 years should be used, but has allowed another period where the source demonstrates that recent operations are abnormal [see 40 CFR 52.21(b)(21)(ii); see also 45 FR 52676, 52718 (1980)]. The WEPCO baseline period is an example of this. In this instance, plant utilization was disrupted by physical problems that led to nonroutine physical changes to remedy those problems. Consequently, EPA determined that a period prior to the onset of such problems was representative of normal operations, and as required by its

regulations, used this period to establish the baseline. The period used was also within the contemporaneous period specified in 40 CFR 52.21(b)(3)(ii). It should be emphasized that, in the WEPCO case, the parties and the court agreed that 1983-84 (prior to discovery of steam drum cracks) should be the baseline years (slip op. at 26); these years had an average 29 percent utilization rate. We continue to believe this is the appropriate baseline period for the Port Washington renovation.

B. Calculating Post-Change Emissions Under PSD.

The court concluded that "EPA's reliance on an assumed continuous operation as a basis for finding an emissions increase is not properly supported" (slip op. at 30). Although the court held that EPA cannot, in this case, wholly disregard past operating conditions at the plant, it also held that EPA could not reasonably rely on the company's own unenforceable projection of operating conditions (slip op at 29). The court remanded the question of PSD applicability to EPA for further proceedings not inconsistent with its decision.

Before the court remanded EPA's determination, it attempted to ascertain whether, in fact, the proposed project would be a major modification even using the assumptions least likely to result in an emissions increase. The court felt (and we agree) that such a "best" case scenario for WEPCO would assume that the "present hours and conditions" would not change at all following the renovations (despite, of course, WEPCO's own estimates of at least tripling of utilization over current levels) (slip op. at 31, n. 14). The court, however, lacked the data to make this calculation, as it could not determine whether

a major modification would result using a set of assumptions most favorable to WEPCO. Therefore, the court remanded the determination to EPA for further consideration.

A conceivable interpretation of the court's opinion is that EPA *must* calculate WEPCO's post-modification emissions increases based on "present hours and conditions." However, for the reasons discussed below, EPA believes that this interpretation is incorrect. Under such an interpretation, EPA would determineWEPCO's post-renovation annual emissions in tons per year (tpy) by simply projecting into the future the hours of operation and conditions (i.e., hourly emissions rate) that existed just before the renovations. This is the interpretation urged by WEPCO in a February 9, 1990 letter to EPA. Such a calculus will always result in exactly the same level of emissions before and after the physical change, and thus would always exempt "like-kind replacements" from PSD review. In addition, calculating emissions increases using this assumption would flatly contradict the record in this case. The WEPCO has stated that it will greatly increase capacity utilization over both current levels and the baseline levels used in the previous determinations. Capacity utilization in terms of heat input to the plant (based on nameplate capacity) during 1978-1979 was about 40 percent (Record item 7.4, WEPCO Submission, April 19, 1988 meeting with EPA). During the 1983-1984 baseline period, it was approximately 27 percent. *Id.* It has since declined to less than 10 percent (1988-1989 data). *Id.* The WEPCO has advised the State of Wisconsin that it intends to return to a forecasted 42 percent utilization level in the years following renovation with an upper maximum forecast of 50 percent [Letter from Walter

Woelfle, WEPCO, to Dale Zeige, Wisconsin Department of Natural Resources, March 29, 1990, Table 7 (enclosed)]. It would be wrong to assume that unit 5 would not be operated at all in the future when an explicit purpose of the renovation is to bring the unit back on line at its original design capacity; moreover, unit 5 is presently inoperative. Most importantly, this methodology is not fairly discernible from any reading of the current regulations. In addition, using "present hours and conditions" would disregard planned changes at WEPCO that will affect the post-renovation hourly emissions rate [e.g., increased capacity, lowering of sulfur content, and enhancement of the electrostatic precipitators (ESP)].

The court upheld EPA's position that increased utilization in the future that is linked to construction or modification activity should not be excluded in determining post-renovation emissions. Nevertheless, the court told EPA not to automatically assume 100 percent utilization in the future when historical data are available. The WEPCO has definite plans to return the plant to historical levels of utuilization that are well above baseline levels of utilization, and which could not be physically or economically attained but for the renovation project. Accordingly, EPA believes it is consistent with the court decision for EPA to base its remand decision on these facts and not rely on the present hours and conditions as conclusive of post-renovation emissions. After a thorough review of the possibilities, EPA has concluded that the court intended that estimates of future emissions for WEPCO's "like-kind replacements" should *consider* historic pre-renovation operating hours and production rates, as well as other relevant factors, in estimating future utilization levels, and should also consider the increased capacity, switching

to lower-sulfur fuel, and other changes affecting the hourly emissions rate for PSD purposes. Consequently, for WEPCO's "like-kind replacements," EPA will compare representative actual emissions for the baseline period to estimated future actual emissions based on all the available facts in the record. Specifically, in calculating post-renovation actual emissions, this approach takes into account 1) physical changes and operational restrictions that would affect the hourly emissions rate following the renovation, 2) WEPCO's pre-renovation capacity utilization, and 3) factors affecting WEPCO's likely post-renovation capacity utilization.

To quantify WEPCO's estimated future actual emissions after the proposed changes EPA relied heavily on projected and historical operational data (e.g., fuel consumption, MMBTU consumed) representative of the source. Specifically, the Agency considered available information regarding (1) projected post-change capacity utilization filed with public utility commissions; (2) Federal and State regulatory filings; (3) the source's own representations; and (4) the source's historical operating data. As described below, EPA determined an appropriate utilization factor for future operations and combined this with post-change emissions factors (to the extent they are or will be made federally enforceable) to estimate a future level of annual emissions for the purpose of determining whether the proposed physical and operational changes would be considered a major modification for PSD purposes. Where a significant emissions increase is projected to occur, WEPCO could voluntarily agree to federally-enforceable limits on any aspect of its future operation (including physical capacity and hours of operation) to ensure that no significant emissions increase will occur.

IV. THE AGENCY'S REVISED PSD APPLICABILITY DETERMINATION

A. Estimated Future Actual Emissions.

The Agency has revised its October 14, 1989 PSD applicability determination for WEPCO's proposed Port Washington renovation based on a "representative actual" to "estimated future actual emissions" comparison (as outlined above). As previously discussed, estimated future actual emissions projections take into account the likelihood that the plant will operate in the future as it has in the past.

The stated purpose of WEPCO's renovations is to refurbish the power plant units to an "as-new" condition in terms of their capacity, efficiency, and availability. Consequently, EPA has used actual, historical, operational data representative of the planet's past operations, approximating an "as-new" configuration, to calculate "estimated future actual emissions." The Agency has verified these data by comparison to WEPCO's own projections of post-renovation capacity utilization and industry averages.

As to the emissions factors used to calculate future emissions, EPA has used WEPCO's own emissions factors for future hourly emissions rates. These emissions factors are based on WEPCO's own assumptions regarding future sulfur in fuel and control technology performance levels. However, since these assumptions go beyond current State implementation plan (SIP) requirements, they must be made federally enforceable for EPA to continue to consider them for PSD applicability purposes.

Operational data (i.e., heat input) from the years 1978-1979 show a capacity utilization factor of 42 percent. These data points represent the closest projection of

WEPCO's operational characteristics, approximating an "as-new" state, as currently available to EPA. The data currently available to us regarding WEPCO's past operational levels are limited to a 10-year period. The Agency believes that these historical levels of operation are representative of the plant's past operations in an "as-new" condition. In addition, the 1978-79 data points appear consistent with WEPCO's own projection of future operations for the year 2010 (as submitted to the Wisconsin Department of Natural Resources on March 29, 1990) and common capacity levels for the utility industry, in general, for new units. However, by this letter, EPA is requesting that WEPCO submit operational data from previous years (i.e., pre-1978), if such data show heat input levels notably higher than the 1978-1979 levels.

As previously mentioned, to calculate future emissions levels for each pollutant, EPA assumed that the amount of future coal consumed in terms of heat input to the plant would be comparable to WEPCO's annual average 1978-1979 coal-consumption figure. On March 29, 1990, WEPCO submitted to the Wisconsin Department of Natural Resources information which contained estimates of future emissions for different levels of coal and heat input to the plant. The Agency used these estimates to establish future emissions based on 1978-1979 heat-input values. Again, it is important to note tht EPA's calculation of "estimated future actual emissions" is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the emissions factors (based on control technology performance levels and sulfur in fuel) used to calculate future emissions are

made federally enforceable. Otherwise, the calculation of estimated future actual emissions for each pollutant will need to be revised by EPA based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions in the current SIP would result in higher projected future emissions than assumed in EPA's calculations and, consequently, could affect the indicated PSD applicability finding.

B. Revised Finding

In sum, EPA has considered past operations at WEPCO's Port Washington plant in estimating future actual emissions. Specifically, EPA has relied on the 42 percent utilization level (in terms of heat input) during 1978-1979. The Agency believes this is a reliable indicator of future utilization because it is consistent both with WEPCO's own projections of post-renovation operations and typical industry usage. The Agency has also considered post-renovation emissions rates on the assumption that they will be made federally enforceable. Compared to the 1983-1984 baseline period, those hourly rates are lower for SO_2 and PM, and unchanged for NOx. The 42 percent estimated post renovation capacity utilization is substantially higher than the 29 percent utilization level during the baseline period. However, in calculating total annual actual emissions, that increased usage is offset for SO_2 and PM by the decreased hourly emissions rates resulting from improvements to control systems and the use of low sulfur coal. Consequently, WEPCO is not subject to PSD review for those pollutants.

In the case of NOx, there will be a direct correlation between increased utilization resulting from the renovations

and increased actual emissions. Hence, WEPCO is subject to review for that pollutant and must obtain a PSD permit. The company should contact the Wisconsin Department of Natural Resources regarding the processing of a permit application for NOx. Due to insufficient source-specific information regarding emissions factors, PSD applicability for PM-10, lead, and noncriteria pollutants listed at 40 CFR 52.21 (b)(23)(i) and (ii) cannot be determined at this time. The PSD applicability for these pollutants should also be based on the "actual-to-actual" emissions test described herein.

This PSD applicability determination applies to WEPCO's currently planned renovations to units 1-5 (see Enclosure A), or, if WEPCO no longer wishes to proceed with renovating unit 5, only the renovation of units 1-4 (see Enclosure B). However, a decision to cancel the currently planned renovations to unit 5 could result in a PSD review for that unit should WEPCO reconsider renovating it some time in the future.

It is our understanding that WEPCO proposes to avoid triggering NSPS for SO_2 and PM at units 1 and 4 by using dry sorbent injection and improving the existing ESP's to offset the potential emissions increases of these pollutants. To the extent that the controls are federally enforceable, and no increase in hourly emissions would occur at maximum capacity, WEPCO can use these options to avoid triggering NSPS for PM and SO_2 at units 1 and 4. However, the two units are still subject to the NSPS requirements for NOx. Unit 5 cannot, however, avoid triggering NSPS for any pollutant and, therefore, is subject to the NSPS requirements for NOx, SO_2, and PM.

Sincerely,

/s/ William G. Rosenberg
William G. Rosenberg
Assistant Administrator
for Air and Radiation

3 Enclosures

Table 7 03/29/90

PORT WASHINGTON
POWER PLANT
MAY 1989 FORECAST
Units 1-5

YEAR	MEGAWATT HOURS GENERATED	CAPACITY FACTOR	FUEL CONSUMPTION COAL (13200 Btu/lb) BURNED TONS
1995	825,288	0.24	365,548
1996	941,779	0.27	415,332
1997	1,081,002	0.31	475,624
1998	1,114,313	0.32	490,868
1999	1,247,296	0.36	546,546
2000	1,349,329	0.38	589,569
2001	1,391,882	0.40	608,621
2002	1,481,464	0.42	646,617
2003	1,420,120	0.41	620,153
2004	1,432,122	0.41	625,174
2005	1,431,412	0.41	624,904
2006	1,460,471	0.42	637,519
2007	1,488,124	0.42	649,133
2008	1,481,423	0.42	646,909
2009	1,463,981	0.42	638,750

PORT WASHINGTON
POWER PLANT
UPPER MAXIMUM FORECAST
Units 1-5

YEAR	MEGAWATT HOURS GENERATED	CAPACITY FACTOR	FUEL CONSUMPTION COAL (13200 Btu/lb) BURNED TONS
1995	1,074,957	0.31	473,981
1996	1,202,460	0.34	528,838
1997	1,341,074	0.38	587,412
1998	1,390,470	0.40	609,237
1999	1,501,584	0.43	654,718
2000	1,600,500	0.46	696,483
2001	1,651,930	0.47	718,252
2002	1,748,046	0.50	760,000
2003	1,690,000	0.48	735,000
2004	1,690,000	0.48	734,000
2005	1,690,000	0.48	734,000
2006	1,710,000	0.49	741,000
2007	1,720,000	0.49	748,000
2008	1,720,000	0.49	747,000
2009	1,695,000	0.48	737,000

Enclosure A

Revised PSO Applicability Determination
Port Washington Power Plant Renovation of Units 1-5

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Estimated Future Actual Emissions (2)	Net Emissions Change	PSD Significance Level	Subject to PSD Review (3)
Particulate matter (4) (5)	328	323	-5	25	no
Sulfur dioxide (4)	24,236	15,919	-8,317	40	no
Nitrogen oxides (5)	2,592	3,405	813	40	yes
Carbon monoxide	144	217	73	100	no
Hydrocarbon	17	25	9	40	no

Other Regulated Pollutants: Due to insufficient source-specific information regarding emission factors, PSD applicability for PM-10, lead and noncriteria pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) cannot be determined at this time.

1) Average actual emissions for 2-year period defined by calendar years 1983 and 1984.

2) Calculated by EPA based on the following information submitted by WEPCO.

a. The average historic firing rate (approximately 17×10^6 per year) for the 2-year period defined by calendar years 1978 and 1979.

b. The emissions estimates for the renovated units based on future coal characteristics (e.g., sulfur and heat content) and actual emissions after pollution controls for particulate.

c. Sulfur dioxide controls applied to units 5 at 75 percent sulfur dioxide removal to comply with NSPS Subpart No. Sulfur dioxide removal of 22 and 13 percent at units 1 and 4, respectively, to exclude these units from NSPS requirements for greater control of sulfur dioxide.

3) If new data indicate that annual, historic-firing rates at the Port Washington facility exceeded historic 1978 and 1979 levels, the indicated applicability determination could change.

4) The calculation of estimated, future, actual emissions for this pollutant is based on WEPCO's projection of annual technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the specific particulate and sulfur dioxide emissions factors used for units I-5 to calculate future emissions (based on particulate and 50, control technology performance levels and fuel sulfur and heat content) are made federally enforceable. Otherwise, the calculation of estimated, future, actual emissions for this pollutant will

be revised by EPA, based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions factors would result in higher, projected, future emissions and, consequently, could affect the indicated PSD applicability finding.

5) Baseline emissions (actual emissions for 2-year period defined by calendar years 1983 and 1984) have been revised based on additional information submitted by WEPCO.

Enclosure B

Revised PSD Applicability Determination
Port Washington Power Plant Renovation of Units 1-4

(all emissions calculations are in tons per year)

Pollutant	Actual Emissions Baseline (1)	Estimated Future Actual Emissions (2)	Net Emissions Change	PSD Significance Level	Subject to PSD Review (3)
Particulate matter (4) (5)	328	339	11	25	no
Sulfur dioxide (4)	24,236	18,505	-5,731	40	no
Nitrogen oxides (5)	2,592	3,396	804	40	yes
Carbon monoxide	144	217			
Hydrocarbon	17	25			

73	100	no
9	40	no

Other Regulated Pollutants: Due to insufficient source specific information regarding emission factors, PSD applicability for PM-10, lead and noncriteria pollutants listed at 40 CFR Section 52.21 (b)(23)(i) and (ii) cannot be determined at this time.

1) Average actual emissions for 2-year period defined by calendar years 1983 and 1984.

2) Calculated by EPA based on the following information submitted by WEPCO:

a. The average, historic-firing rate (approximately 17 x 10^6 per year) for the 2-year period defined by calendar years 1978 and 1979.

b. The emissions estimates for the renovated units based on future coal characterization (e.g., sulfur and heat content) and actual emissions after pollution controls for particulate.

c. Unit 5 inoperative. Sulfur dioxide removal of 22 and 13 percent at units 1 and 4, respectively, to exclude these units from NSPS requirements for greater control of sulfur dioxide.

3) If new data indicate that annual, historic-firing rates at the Port Washington facility exceeded historic 1978 and 1979 levels, the indicated applicability determination could change.

4) The calculation of estimated, future, actual emissions for this pollutant is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for port renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the specific particulate and sulfur dioxide emission factors used for units 1-4 to calculate future emissions (based on particulate and SO_2 control technology performance levels and fuel sulfur and heat content) are made federally-enforceable. Otherwise, the calculation of estimated, future, actual emissions for this pollutant will be revised by EPA, based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions factors would result in higher, projected, future emissions and, consequently, could affect the indicated PSD applicability finding.

5) Baseline emissions (actual emissions for 2-year period defined by calendar years 1983 and 1984) have been revised based on additional information submitted by WEPCO.

EXHIBIT 35

IN THE UNITED STATES COURT OF APPEALS
FOR THE SEVENTH CIRCUIT

Nos. 88-3264
89-1339

WISCONSIN ELECTRIC POWER COMPANY,

Petitioner,

v.

WILLIAM K. REILLY, Administrator
United States Environmental
Protection Agency, *et al.*,

Respondents.

ON PETITIONS TO REVIEW FINAL ACTION
OF THE UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY

AFFIDAVIT IN SUPPORT OF RESPONDENTS'
MOTION FOR EXTENSION OF TIME

AFFIDAVIT OF GREGORY B. FOOTE

1. My name is Gregory B. Foote. I am a staff attorney in the Office of General Counsel at the U.S. Environmental Protection Agency ("EPA") in Washington, D.C. I have held this position since 1985. In this capacity I have primary responsibility within the Office of General Counsel

for advising and representing EPA in matters involving the prevention of significant deterioration ("PED") provisions of the Clean Air Act, 42 U.S.C. §7470-7479.

2. This affidavit is filed in support of Respondents' Motion For Extension of Time.

3. I am assigned primary responsibility in the above captioned case.

4. EPA and the United States Department of Justice presently intend to file a Petition for Rehearing in connection with the decision issued by this Court on January 19, 1990.

5. The matter under review is so complex that an adequate brief in support of the Petition for Rehearing cannot reasonably be prepared during the fourteen-day period allowed under Circuit Rule 40(d) for the following reasons:

(a) The Court's decision of January 19, 1990 largely upheld EPA's applicability determinations ruling that an extensive renovation project at the Port Washington power plant owned and operated by petitioner Wisconsin Electric Co. ("WEPCO") would be subject to new source requirements under the Clean Air Act, 42 U.S.C. § 7401, *et seq.* However, the court vacated EPA's determination that the calculation of future increases in "actual emissions" for purposes of determining applicability of the PSD provisions of the Act should be made using the "potential to emit" concept in 40 C.F.R. § 52.21(b)(21)(iv). Slip op. at 28-31. The Court also rejected WEPCO's proffered view that emissions increases following the renovations should be calculated based on the company's own unenforceable estimates of emissions. *Id.* at 29. The Court remanded the

PSD applicability determination to EPA for further proceedings not inconsistent with its opinion. *Id.* at 33. The Court further appeared to suggest that EPA could, on remand, calculate future emissions based on "whether the renovated plant would cause a significant net emissions increase if it were operated under present hours and conditions." *Id.* at 31 n. 14.

(b) EPA has tentatively concluded that the analysis employed by the court in deciding to vacate EPA's PSD applicability determination is faulty, and for this reason, EPA presently intends to file a petition for rehearing in which it will ask the Court to reinstate EPA's applicability determination. In addition, EPA presently expects that its petition for rehearing will, in the alternative, seek clarification of the Court's January 19 decision. However, as explained in paragraph (c) below, EPA at present is unclear as to the meaning or impact of the Court's decision.

(c) EPA staff are actively engaged in reviewing the Court's decision, including the suggestion on page 31 n. 14 for EPA action on remand. At this juncture, it appears that the Court's suggestion may not comport with any known method of calculating emissions increases under EPA's regulations. Consequently, EPA has not yet come to any conclusion as to the meaning or impact of the Court's decision on either the WEPCO project or the many other similarly situated sources which may be affected by that decision. I anticipate that several days of review and analysis will be necessary before EPA staff are able to present to EPA management their views as to the meaning and impact of this decision on the exceedingly complex PSD program. Only at that point will EPA be in a position to determine whether further clarification of the Court's

decision is appropriate and, if so, what clarifying order would be sought.

Pursuant to 28 U.S.C. 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed this 26th day of January 1990 at Washington, D.C.

/s/ Gregory B. Foote
Gregory B. Foote

EXHIBIT 36

PROCEEDINGS OF THE ACID RAIN CONFERENCE

Springfield, Virginia

April 8-9,1980

Prepared by:

Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1980

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Dr. Gage: Ladies and Gentlemen, I would like to call this session to order. I am Steve Gage the Assistant Administrator for Research and Development. I am very pleased to welcome you here to this historic meeting on acid rain. During the next two days, we hope that all of us will gain a much better insight into the acid rain problem and learn more about what can be done to lessen its impacts.

As many of you are aware, this meeting follows, by less than a month, an important scientific meeting which was held in Norway. From that meeting we know that our state-of-the-knowledge remains incomplete, but that our state-of-the-knowledge is indeed changing very rapidly. There are now hundreds of scientists in Sweden, Norway, Canada, England, Germany, the United States, and other countries working on this problem. I am convinced that during the next few years we will see a dramatic advance in our understanding of the acid rain problem. I am also convinced from what we have learned, that the problem we will be discussing for the next twenty-four hours is not just a passing fad – it will occupy our attention well beyond this day and probably for most of the decade of the 1980s.

The impacts of acid precipitation affect wide geographical areas in virtually the entire aquatic and terrestrial ecosystem. Acid rain has the potential to cause severe

economic damages which can only become more costly should we delay in recognizing its full scope. Most importantly, it is not clear, at this time, whether the impacts of acid rain are, for all practical purposes, reversible. So it is very important that we begin today to establish a dialogue about this problem, and I invite you to join with us in seeking the best approaches for its solution.

* * *

As a practical matter, the only way to reduce acid deposition is to reduce the emissions of sulfur and nitrogen oxides, the pollutants that cause the problem. Among the major sources of these pollutants are utilites and power plants. Last year we set emission standards for new power plants which will prevent them from contributing significantly to the problem of acid deposition, however, there are hundreds of older plants that are either uncontrolled or poorly controlled. Any effective plan to reduce acid deposition will of necessity require reducing emissions from these older plants.

As the Nation backs away from oil and returns to coal for its energy needs, reducing total regional emissions will not be easy but it can be done. I wholeheartedly support coal conversion, it is essential that this Nation reduce its dependence on imported oil. I strongly believe, and have consistently stated publicly, that we can switch to coal and at the same time protect against environmental degradation. As we do so, we must realize that the distribution of coal reserves in this country precludes us from relying simply on low sulfur coal. The welfare of our miners and the economies of our Eastern and Midwestern coal-producing States require that we find ways to use all our

coal. The new source performance standards for coal fired power plants allows for just that.

I know many of you are also concerned with the economic effects of being down wind of interstate transport of air pollutants. In reality all States import and export air pollution. When one State is forced to clamp down on sources within its borders to compensate for pollution coming from a neighboring State, its industry unfairly may bear an

* * *

Moving to another possibility, and that is the definition of modification or reconstruction. It may be possible to modify the definition so that activities at a plant which tend to extend the useful life of that plant or tend to increase the total emissions generated over the total life of that plant could be legally defined as a reconstruction or modification which would, if those activities were undertaken, then cause the plant to be governed by the new source performance standards. Now, the positive aspect of that is that some of our current existing sources which are subject to relatively high emission limits, if they were to extend their useful life substantially, might be brought into the new source performance standards system. That regulatory requirement might cause one of two effects, it might cause a retirement of that facility rather than an extension of its life, or it might cause the retrofit of a source in order to meet the new source performance standard emission limit. The negative side is that there would likely be litigation over any modification of our definition, enforcement might be difficult, the activities that tend to extend useful life are largely a function of what the utility or other source is saying about the effects

of those modifications. It might be fairly easy to get into arguments with the sources about these particular physical changes and whether they would have the effect of extending the useful life. If we define the cutpoints, the type of activity that shifts you from one gain to the other too strictly, then you you could wind up imposing some very costly retrofits.

Well there are a number of other items which I would like to identify; that are things that the States may be able to do under their current legal authority, at least some States certainly can do some of these

* * *

EXHIBIT 37

ACID RAIN AND NONATTAINMENT ISSUES

HEARING

BEFORE THE

SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION

OF THE

COMMITTEE ON
ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE

ONE HUNDREDTH CONGRESS

FIRST SESSION

TO HEAR FROM HON. LEE THOMAS, ADMINISTRATOR, ENVIRONMENTAL PROTECTION AGENCY ON THE SUBJECT OF ACID RAIN AND NONATTAINMENT ISSUES

APRIL 22, 1987

Printed for the use of the Committee on
Environment and Public Works

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Senator BURDICK. Mr. Thomas, side-by-side comparisons of emission reductions by the United States and Canada are difficult because of differences in governmental forms and regulatory regimes. I understand that the eastern provinces of Canada, in an effort to reduce acid rain, have committed themselves to a 50 percent reduction in emissions by 1994. Do you understand that to be correct?

Mr. THOMAS. They have, Senator. They're in the process now of moving forward with implementation. That commitment was made a couple of years ago. They've still got a couple of provinces that have not yet implemented that commitment, but they're moving forward with that kind of commitment.

Senator BURDICK. I discovered something else recently, that as you move farther west in Canada through the provinces, that percentages go down. I understand that in Saskatchewan it isn't 50 percent, it's 25 percent, and it feathers out until you hit the Pacific coast. Is that correct?

Mr. THOMAS. Senator, let me say first, we are in the process of reviewing with Canada how they are implementing their control program. We are doing that because of our interest in learning more about how they're implementing it. We're also doing it in response to detailed questions we've received from the House Energy and Commerce Committee.

The Canadians have a different approach than we do. They don't have the strong Federal standard-setting authority that I have, for instance. That is largely an authority that the provinces have, so they work through an arrangement with the provinces to implement their

standard-setting process. They don't have the 15-year reduction history we've got from strong Federal standards on sulphur dioxide, as an example.

Now, within that they also have different ways of looking at, what do you consider a violation? Is a violation the kind of violation that we've got, or do you accommodate violations by production cutbacks as far as plant operations are concerned? So is it an ambient violation close to the plant that we're controlling, or is it an overall loadings violation that may be controlled through a production cutback over a year's period of time?

Looking at those issues and working with the Canadians to find out more about how they control their emissions is one of the things we're doing right now. I must say, though, that the kind of commitment that the Canadians made two years ago, that they're working through to implement, I commend them for. My friend, Tom McMillan, who is the Environment Minister in Canada, and I have had numerous discussions about the difficulty of implementing that and the difficulty that we have in the United States of implementing our control programs, and we're working closely to understand exactly how each of us implements our laws.

Senator BURDICK. Well, I'm asking this question because, after all, thin matter of air pollution is continental. It isn't only the United States; it's a continental matter. We are well aware that Canada doesn't have scrubbers on any of their powerplants. We understand that. They are trying to use clean coal technology and so forth, they talk about a 50 percent reduction, and as you go west they feather down to 25 percent and to nothing. I wonder if they're making a real effort, that's all.

Mr. THOMAS. There's a real question about that in a number of people's minds, and we're working that, issue.

Senator BURDICK. What is your opinion? Should any acid rain bill that we enact after 1987 require scrubbers in the midwest in the future?

Mr. THOMAS. Senator, first, I don't feel we're at a point where acid rain legislation should be enacted by Congress. I do not feel like a requirement for emissions reductions beyond those that we have ongoing under the Clean Air Act is evident today that would require acid rain controls.

Given that position, if you decide to move forward with an acid rain control bill, I feel that legislation should be one that looks at an approach that builds in flexibility. It's aimed at total loadings reductions, but it builds in the most cost-effective way to go about getting that, which in many cases, I think, will result in not having scrubbers. But I think that it will allow – should allow – the States to clearly interplay with their utilities in determining how those total loadings should be reduced. It should include emissions trading. It should include flexibility in making that decision between coal switching, new clean coal technology, or scrubbers. I do not feel that those things should be mandated.

Senator BURDICK. You don't think the future bill after 1987 should require scrubbers?

Mr. THOMAS. No, sir, I don't. I don't think you should have a mandated scrubber technology.

Senator BURDICK. Aren't we slipping backwards a bit?

Mr. THOMAS. No, sir. Under new sources – the issue on acid rain is, are you going to mandate scrubbers on existing

sources? All new sources in the United States, as you know, have scrubbers. We've got 150 of them with scrubbers now and 50 more on order, more than any other country in this world.

The issue is, are you going to go back and require retrofitting of your existing utilities? I don't think the concept of mandating retrofitting of scrubbers on existing utilities is the way to go at all.

Senator BURDICK. What do we do?

Mr. THOMAS. I think that if you decide to go forward, which I don't think you should do – if you decide to go forward and mandate additional reductions from those existing powerplants, I think you should build in the flexibility for the most cost-effective way to get those reductions, which includes the concept of switching fuels, the concept of new technology, the concept of scrubbers, the concept of conservation, all built in so that you have environmental and cost built in together in an effective way to get reductions in loadings.

Senator BURDICK. Well, I understand you, Mr. Thomas, but pardon me if I say it looks like we're retreating a bit if we're not going to be as firm as we have been in the past.

Mr. THOMAS. Retreating from what, Senator?

Senator BURDICK. Well, the requirement for scrubbers, for example.

Mr. THOMAS. But the requirement for scrubbers has always been on new sources.

Senator MITCHELL. Thank you, Senator Burdick.

Senator Chafee?

Senator CHAFEE. Thank you, Mr. Chairman.

Briefly – and I just want to get this quickly from you because I want to move on to something else – the problem we've got is that the new source performance standards obviously impose stiff requirements on new, sources, so therefore what's happening in our country is that we're not having new sources, that they are keeping the old plants going because there is less expense in so doing.

Many of us feel that we ought to be in a situation where we should be requiring the new source performance standards on the older plants because the theory was that the older plants eventually would expire, and then you would get new and more efficient plants – efficient as regards the release of pollutants. That's not happening.

What are you suggesting we ought to do? Why shouldn't we impose these new source performance standards on the old plants?

Mr. THOMAS. Well, first, Senator, I don't think you should impose them on the old plants because I don't think there's a scientific rationale for requiring that kind of emission reduction that you'd get from a new source performance standard, either as far as total loadings is concerned, as it relates to environmental damage, or the kind of specific definition that you would give to one location receiving damage from a particular plant. I don't think that there's a rationale for suggesting that you've got to have those new source standards on those old plants today or next year.

The problem you've got is as you stated. This country has decided not to go forward with the nuclear option,

which was one we were pursuing aggressively a number of years ago. A lot of the new sources, as far as utilities were concerned, were nuclear at that point in time.

We also, now, are looking at how we can go forward and extend the life of our existing sources. We have found through technology development a number of ways to do that cost-effectively, repowering ways, retrofitting ways to extend those lifetimes. So in fact, we have to deal with, is that going to be an environmental issue for us or a public health issue? I don't think it's going to be a public health issue; there's debate on that. I don't think it's going to be an environmental issue; there's debate on that. I may change my mind on that, but today I don't think you've got the basis to go in and suggest that all of those old sources should put on very stringent control requirements that we impose on the new source performance standards.

Senator CHAFEE. Well, Mr. Thomas, what's the problem here? Is it your belief that the current emissions in the United States are not causing enough damage to cause you to enact stronger restrictions than currently exist? I mean, no one knows more about the damage that has taken place in Europe. You've seen it. You've seen the lakes in Sweden. You've seen the forests in Switzerland and West Germany, and, in your mind, you just are not convinced that that damage is taking place in the United States. Is that the problem?

Mr. THOMAS. That damage, connected with the emissions levels that we've got in the United States? That's correct.

* * *

EXHIBIT 38

EXPERT REPORT OF
KENNETH SCHWEERS

DUKE ENERGY CORPORATION

AUGUST 15, 2002

/s/ Kenneth A. Schweers
Kenneth Schweers

I. INTRODUCTION

I am Kenneth Schweers, and I have just recently resigned as Chief Operating Officer of Development Alternatives, Inc. I have been asked by Duke Energy Corporation to provide an expert report in connection with this litigation. This report describes the assumptions made by the United States Environmental Protection Agency ("EPA") in the studies I did for the consulting firm ICF Incorporated on behalf of EPA evaluating the economic impact of environmental legislation and regulations, including EPA's New Source Performance Standards ("NSPS"), Prevention of Significant Deterioration ("PSD") and Non-Attainment New Source Review ("NNSR") regulations. I will refer to these regulations collectively as the "New Source Review" or "NSR" regulations or programs. In my opinion, from the mid-1970s through the 1980s, EPA believed the

- the focus of the NSR programs was to regulate emissions from new plants, not existing plants;
- the NSR requirements would not be triggered by existing coal-fired plants that operated at their original capacity and took actions necessary to maintain that capacity; and

- significant emissions reductions from existing coal-fired power plants would not be achieved through the application of the NSR programs and that new and additional legislative and regulatory programs were necessary to achieve reductions from existing plants, such as the "Acid Rain" regulations adopted in the Clean Air Act Amendments of 1990.

II. Summary of Qualifications and Preparation of this Report

I am an industrial and nuclear engineer and economic analyst by training. I received a Bachelor of Science in Industrial Engineering from Stanford University (1969). After graduation, I worked as a project manager for the U.S. Navy, where I assisted in directing the work of contractors in the design of reactor cores for submarines and heavy reactor equipment

* * *

The ICF studies used the aforementioned computer model that simulated the dynamics of the electric utility sector and the coal industry to estimate the economic and environmental impact of various legislative and regulatory proposals. The studies evaluated the economic impact by: (1) establishing a "base case" that assumed the pre-existing regulatory requirements with no new environmental requirements; (2) identifying the additional environmental requirements imposed by the legislative or regulatory proposals being evaluated; and (3) forecasting the incremental impact on the utility and energy producing sectors by adding the proposed environmental requirements to the pre-existing regulatory regime. The

assumptions used in the base case and the proposed requirements were either provided or approved by EPA.

NSPS Studies

In 1977 and 1978, ICF conducted economic impact studies under contract to EPA evaluating amendments to the NSPS regulations to implement the Clean Air Act Amendments of 1977. These studies, which I conducted, were designed to assist EPA in its review of proposed additions to the then existing NSPS regulations and to support its final rulemaking amending the NSPS.

The base cases for these studies incorporated various understandings and assumptions about how coal-fired plants were operating and being regulated. These understandings were either communicated by EPA to ICF, or suggested by ICF and approved by EPA. For the base case, EPA understood and assumed that existing plants were complying or would comply with then current Federal regulations (e.g., NSPS) and the State Implementation Plans (SIPs). We then modeled the potential impact of various alternative amended NSPS, each of which included its own set of understandings and assumptions that were approved by EPA. Both the base cases and the proposed alternatives shared a common understanding and assumption adopted by EPA: that existing coal-fired power plants would continue to operate at original capacity without being required to retrofit scrubbers.[1] EPA

[1] By "original capacity," I mean the design net dependable capacity that is available to the electrical power grid. This accounts for the energy needs of the plant itself to operate, and is different from what is often referred to as nameplate or gross capacity.

recognized that existing coal-fired power plants would be required to meet only the emission limits that had been established in the SIPs for existing plants.

The ICF analysis included estimates of operation & maintenance (O&M) costs. EPA did not direct ICF to assume that these O&M expenditures that allowed the plants to operate at their original capacity would trigger NSR requirements and the attendant cost of retrofitting pollution control equipment. Had EPA instructed ICF to assume that O&M expenditures would trigger NSR, ICF would have included such costs in the model's assumptions. For example, when modeling the costs of complying with SIPs, ICF evaluated the costs associated with SIP compliance options such as switching to low-sulfur coal or installing scrubbers. For purposes of the NSPS studies, EPA never asked ICF, however, to calculate what would have been the additional cost under NSR of retrofitting scrubbers to existing plants that operated within original capacity and were already in compliance with the SIPs.

The NSPS studies focused on the costs associated with designing and operating new facilities under a variety of regulatory scenarios. The impact of regulatory proposals on new plants could be accurately evaluated by relying on accepted engineering assumptions. The NSPS studies did not evaluate the costs of regulatory proposals on existing plants, which is a substantially different exercise that has to take into account a number of factors reflecting the range of financial, physical, technical and geographical constraints on existing plants. It was in the context of the acid rain initiative that EPA asked ICF to conduct economic evaluations of significant legislative or regulatory options for reducing emissions from existing plants.

Acid Rain Studies

After EPA promulgated the NSPS and PSD regulations in 1979-1980, ICF conducted a number of studies for EPA in the 1980s addressing the issue of acid rain. "Acid rain" is acidic precipitation resulting from accumulated atmospheric loadings of SO_2 and NOx. The ICF acid rain studies supported the efforts of various governmental agencies, including EPA, to evaluate regulatory and legislative proposals to reduce total SO_2 and NOx emissions, primarily from existing coal-fired power plants. While at ICF, I conducted or oversaw the conduct of these studies.

The "base cases" for these acid rain studies projected emissions based on the understanding that the then current environmental regulatory regime remained unchanged. EPA believed that SO_2 and NOx emissions from existing coal-fired power plants would be relatively constant under existing law. This assumption was based on plants operating at their original capacity at their allowable emissions level. EPA did not request ICF to study, whether under existing law, SO_2 emissions from existing coal-fired plants would decrease because of the application of NSR and the attendant retrofitting of pollution control equipment. EPA also did not direct ICF to assume that variations in actual operating or emissions levels, such as periodic decreases associated with maintenance followed by increases back to original capacity, would trigger NSR. In other words, EPA believed that existing coal-fired power plants would continue to operate without triggering NSR.

The focus of the acid rain proposals we evaluated on behalf of EPA and other government agencies was reducing

the SO_2 and NOx emissions from existing sources. EPA believed that new regulations and the legislative programs would be needed to achieve these reductions and that significant SO_2 and NOx reductions would not be achieved by retrofitting scrubbers or other pollution control equipment on existing plants through the application of NSR. EPA believed that SO_2 and NOx emissions at existing plants would remain relatively constant absent a change in environmental legislation or regulation. The emission-reduction options ICF evaluated in various acid rain studies conducted for EPA in the 1980s included, among numerous others:

- a 30% reduction of SO_2 and NOx emissions;
- a 2.0 lb./mmbtu SO_2 limit;
- a tax on utility emissions of $0.15 per pound of SO_2 emitted;
- the Waxman-Sikorski bill (H.R. 3400), which proposed a 9.5 million ton SO_2 reduction for existing utility plants;
- the Acid Deposition Control Act of 1986 (HR. 4567) which would require a 2.0 lb. SO_2/mmbtu limit, to be followed by a 1.2 limit; and
- an option EPA considered to require existing plants to meet NSPS when they reached 30 years of service.

At the direction of EPA. ICF evaluated these proposals against the base case assumption that existing law, including the NSR programs, would not require significant SO_2 and NOx emission reductions from existing plants operating at their original capacity.

Beginning in 1985, EPA believed that existing plants would operate for 60 years. EPA also understood that utilities would have to repair or replace components as required to continue to operate to this longer lifetime. ICF recognized that these costs occurred throughout the life of the plant and that it was not possible to establish precisely when these replacements or repairs had occurred (or would occur). For modeling and study reporting purposes, however, we assumed that these repairs or replacements would occur at 30 years of the plant's useful operating life and would be referred to as "refurbishment." This mid-life refurbishment was part of the maintenance that the ICF studies assumed would occur at existing coal-fired power plants to allow them to continue to operate at their original capacity and close to their design efficiency. The 1985 and subsequent studies ICF conducted on behalf of EPA all assumed, as EPA directed, that the O&M necessary to keep the plants operating, including the refurbishment at the 30-year mark, would not trigger NSR or scrubber retrofits for those existing plants.

I do not recall any discussion that I had with EPA about the assumptions in these models in which the Agency stated that mid-life refurbishments would trigger NSR and require the existing plants to retrofit scrubbers. Had it been EPA's view that the NSR programs, beginning in 1979-1980, would have achieved significant SO_2 reductions, ICF would have reflected that belief in the acid rain studies we conducted on EPA's behalf. EPA's understanding that NSR would not significantly reduce SO_2 emissions from existing coal-fired plants was further reflected in one of the regulatory proposals EPA asked ICF to evaluate. EPA was considering the automatic imposition of NSPS requirements on existing coal-fired power plants when

they reached the 30-year mark as an alternative regulatory approach to address acid rain. This EPA proposal demonstrates EPA's belief that existing plants would not be subject to widespread retrofitting of scrubbers absent a change in the law.

Most of the acid rain proposals we evaluated for EPA included the option for large-scale retrofitting of scrubbers at existing plants. ICF did not include the retrofitting analyses in the base case because EPA did not view the widespread installation of scrubbers on existing plants to be required under the existing CAA regulatory regime. To project the costs of retrofitting, we had to better understand the specific characteristics of the various types of existing plants. This is because, unlike projecting scrubber costs for new "greenfield" plants which can be estimated rather accurately in a generic manner based on engineering estimates, retrofit costs are dependent on a number of historical and site-specific factors. These factors include the type, location and capacity of the plant, the design of the plant (e.g., types of coal likely to be burned and whether the plant had physical space for scrubbers), and how the plant was intended to be used in the power grid. ICF did not include this type of site-specific analysis, which is necessary to understand retrofitting costs, in its studies for the NSPS rulemakings in 1978-1979, since those rule-makings focused on regulatory proposals applicable to new plants.

Our studies projected that a regulatory program that forced the retrofitting of scrubbers at existing power plants would be very expensive. For example, the study that evaluated the option considered by EPA to impose NSPS on coal-fired plants when they reached 30 years in age projected that by 1995, utilities would incur an incremental annual cost of $3.9 billion in 1985 dollars (this

would be $6.6 billion in 2002 dollars). By the year 2010 the incremental annual cost of retrofitting would increase to $9.4 billion in 1985 dollars (this would be $15.8 billion in 2002 dollars). This incremental annual cost of retrofitting scrubbers included the annual capital charge for the costs for additional equipment (e.g., the scrubbers themselves) installation, incremental increases in O&M costs and any additional fuel costs resulting from the use of additional pollution control equipment. EPA's option to impose NSPS on coal-fired plants when they reached 30 years in age would have required the utility industry to invest by 1995 about $29.8 billion in 1985 dollars (it would be $50 billion in 2002 dollars).

Overall, if EPA's proposal to impose NSPS on coal-fired plants at the 30-year point in their life had been adopted, the utility industry would have been required to invest approximately $69.5 billion between 1990 and 2010 in 1985 dollars (this would be approximately $117 billion in 2002 dollars). Further, these studies noted that there were other uncertainties and constraints associated with retrofitting that would have likely increased the projected costs above those reported in the ICF study. Though our model attempted to take site-specific constraints associated with plant design or location into account, it was able to do so only in the most general way.

* * *

EXHIBIT 40

1989 EPA BASE CASE FORECASTS

Prepared For

The U.S. Environmental Protection Agency

By

ICF Resources Incorporated

May 1989

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INTRODUCTION

This report presents new EPA Base Reference Case forecasts through 2010 of future trends in utility air emissions, utility capacity and generation levels; utility fuel consumption, and regional coal production. These trends were recently re-examined in order to provide up-to-date bases from which economic and emissions impacts under alternative environmental control proposals can be assessed. Two Base Reference Case scenarios (referred to as the High and Low Emissions Cases) were analyzed to present a reasonable possible range of electric utility air emissions over the next two decades.

This report is organized into three sections with three appendices. The first section presents the forecasted trends from the two new EPA Base Cases, as well as a brief analysis of the factors underlying these trends. The second section presents these forecasts in comparison to the previous (1987) EPA Base Case forecasts. The final section presents some of the key assumptions and uncertainties that underlie these forecasts. Appendices A and B present forecasts from the High and Low Emissions Cases, respectively, while Appendix C presents a detailed list of the 1989 EPA Base Case assumptions.

In the High Emissions Case utility sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions are forecasted to rise moderately from recent historical levels in the near-term with continued growth in the long-term. In the Low Emissions Case, emissions remain flat in the near term, grow slightly through 2000, but decline thereafter. Gas-fired capacity options (e.g., combined cycles and turbines) are expected to be chosen for most new, currently unplanned capacity requirements through 2000 in both cases, while a significant amount of new coal capacity is forecasted to come on-line after 2000. National utility gas consumption in the High Emissions Case is expected to rise only moderately from current levels while gas loses market share to oil in many existing utility steam plant markets. In contrast, in the Low Emissions Case, gas gains considerable market share from oil in the near-term. National coal production levels are forecasted to increase steadily, with most regions experiencing some growth from 1985 levels in both cases.

Many important assumptions underlie these forecasts. Several of these assumptions have been substantially revised since the 1987 EPA Base Case analysis (which was based on assumptions developed in late 1986), reflecting important changes in the energy markets. Some key assumptions were varied between the two reference cases to reveal the sensitivity of the emissions and fuel use forecasts to these factors. The most important of these assumptions are presented in the table on the following page.

In general, the assumptions used in the Low Case contribute to lower forecasted emissions growth than in the High Case. In particular:

- Lower electricity demand results in lower coal powerplant utilization.
- Shorter fossil steam powerplant lifetimes result in earlier retirements of higher-emitting existing coal units, which are

Assumption		1989 EPA Base: Reference Case High	Low
Crude Oil Prices (1988$/bbl)	1995	18.00	25.00
	2000	22.00	29.00
	2005	25.00	31.50
	2010	29.50	34.00
Electricity Demand Growth (% per year)	1988-2000	2.8	2.0
	2001-2010	2.3	1.4
Steam Powerplant Lifetimes (years)	Coal/Oil/Gas> 50Mw	65	55
	Coal/Oil/Gas> 50Mw	45	45
	Nuclear	35	40
Cogeneration (billions of kilowatt hours)	1995	175	195
	2000	208	291
	2005	255	382
	2010	313	474
New Non-Fossil Capacity (gigawatts)	2005	0	9
	2010	0	20
Repowered Coal Capacity* (gigawatts)	2000	0	4
	2005	6	20
	2010	10	38

New Unplanned Coal Powerplants Allowed By	2000	2005

* Includes 50% increase in capacity due to repowering.

generally replaced by new lower-emitting gas or scrubbed coal capacity.

- More repowering with clean coal technologies reduces SO_2 and NO_x emissions rates at repowered plants.
- More non-fossil capacity and cogeneration reduces the amount of higher-emitting coal-fired capacity operated and built.

A more detailed discussion of the assumptions, caveats, and uncertainties pertaining to this 1989 EPA Base Case analysis is presented in the final section of this report.

* * *

KEY ASSUMPTIONS

A number of assumptions have important effects on projections of future levels of utility emissions, utility generation and capacity, utility fuel consumption, and coal production. A short list of some of the key assumptions used in the two reference cases is shown on page 2, while a detailed list of the assumptions is presented in Appendix C. Several of the more important assumptions incorporated in this Base Case analysis, and their effects on the forecasts presented herein, are discussed below.

Oil and Gas Prices

Oil and gas prices have a very important effect on the amount of turbine/combined cycle versus coal capacity built. In turn, relative oil and gas prices affect the amount of gas versus oil consumption at existing oil/gas steam powerplants. Accordingly, the level of oil and gas prices have important effects on utility SO_2 emissions.

World oil prices are very uncertain because the world oil market is fundamentally unstable: the lowest cost producer (Saudi Arabia) is also the marginal producer (largely for political reasons). Therefore, it is difficult to define within a narrow range the full spectrum of potential future oil prices. However, future oil prices would be expected to range from levels near recent depressed levels of $17/bbl (reflecting continued market weakness) to moderately higher real prices as the current excess production capacity situation abates.

There is also uncertainty with respect to delivered natural gas prices. Recent ICF gas market assessments suggest that the current gas supply "bubble" will dissipate by around 1990. This is expected to lead to relatively significant increases in prices in the near term such that wellhead prices would be expected to be no lower than $2.60 per million Btu even assuming low oil prices. In the long-term, recent ICF analyses conducted for DOE suggest that gas resources available for production in North America (both in Canada and in the U.S.) are more plentiful than previously thought, and that advances in exploration and extraction techniques will expand the supply of low- to medium-cost gas reserves. Accordingly, wellhead prices increase more slowly in response to greater supplies in the $3 to $4 wellhead gas price range. However, the

trends in gas prices are strongly linked to future oil prices (since gas and oil are substitutes in many applications), and hence are also very uncertain.

Alternative oil and gas prices in the High and Low Cases were assumed to reflect these uncertainties. ICF's projections of oil and gas prices are based on a previous integrative assessment of demand and supply conducted for the DOE which suggested an amount of supply that would be available at given price levels. The specific price projections used in this base case analysis were not developed using a detailed supply/demand model, such an effort would be outside of the intended scope of this project.

In the High Case, lower oil prices were assumed over time, remaining at about $18/bbl through 1995, increasing moderately to reach $22/bb by 2000 and $29.50/bbl by 2010. Accordingly, delivered natural gas prices to utilities (on an average annual, interruptible basis), in New England rise from roughly $2.50/mmBtu recently to $4.10/mmBtu in 2000 and $4.95/mmBtu by 2010. As a result, gas prices are generally higher than most grades of residual oil in this case, thereby leading to relatively more oil consumption. In contrast, in the Low Case, world oil prices are forecasted to increase more rapidly over time, reaching $29/bbl by 2000 and $34/bbl by 2010. Although delivered gas prices are forecasted to be higher than in the High Case ($4.40/mmBtu in New England by 2000, and $5.15/mmBtu by 2010), gas prices are typically lower than competing residual oil prices, so that relatively more gas consumption results in this case. See Appendix C for average annual interruptible prices for gas delivered to utilities in the High and Low Cases as compared to regional residual oil prices.

Because of seasonal fluctuations in the demand for gas from residential and commercial customers, there tends to be relatively high delivered gas prices to utilities in the winter (about 10-20 percent above the annual average price in recent years) and lower delivered gas prices in the summer (about 10-20 percent below the annual average price). Electric utility consumption of gas is assumed to vary seasonally. In the High Case, with relatively low oil prices, gas was generally forecasted only to be consumed by electric utilities in the summer months in the Eastern states. In the Low Case, with relatively low gas prices as compared with oil, gas was generally forecasted to be consumed by utilities during all seasons except the winter months in the Eastern states.

In the West South Central region, gas was forecasted always to be competitive with oil in both the Low and High Cases, with electric utilities consuming all natural gas at oil/gas steam plants in Texas and Louisiana in all years. In California, due to stringent environmental regulations, only gas was assumed to be consumed at oil/gas steam plants.

Scrubber Costs

Lower scrubber costs were assumed in the new EPA Base Case analysis than were used in the 1987 EPA Base Case, reflecting technology improvements in the pollution control industry. These costs are roughly comparable to the lower industry scrubber costs used in a number of EPA acid rain control analyses conducted recently by ICF.[2] The

[2] See, for instance, *Analysis of the Mitchell Compromise Acid Rain Proposal*, September 1988.

new scrubber cost assumptions were based on EPRI/ Stearns-Rogers cost assumptions as interpreted by RCG/ Hagler, Bailly, Inc. (Several key assumptions were made: (1) a contingency factor of 15 percent was used, (2) one spare module was assumed, and (3) scrubbers were assumed to be designed with *no* reheat in contrast to assumptions in the 1987 EPA Base Case.) The cost assumptions for a new NSPS-Da powerplant resulting from this assessment are presented in Table 4.

The net effect of these assessments was that wet scrubbing was assumed to be employed at all unplanned new powerplants, because wet scrubbing cost estimates were lower than dry scrubbing costs estimates. Accordingly, the cost differences in scrubbing high and low sulfur coals were smaller than were assumed in the 1987 EPA Base Case. Furthermore, scrubbed units are forecasted to be higher utilities' dispatch order than in the 1987 EPA Base Case because of lower variable O&M costs associated with scrubbing, thereby increasing forecasted utilization levels somewhat. These effects led to stronger growth in high sulfur coal production than was forecasted in the 1987 EPA Base Case.

Sulfur Level	Lbs. SO_2/mmBtu:
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.54-5.00
Very High Sulfur	More than 5.00

TABLE 4

WET SCRUBBER COSTS FOR NEW UTILITY POWERPLANTS MEETING NSPS SUBPART DA REGULATIONS

	Sulfur Level						
	Very Low	Low	Low Medium	Medium	High Medium	High	Very High
Capital Costs (early '86 $/kw)	108.00	110.00	110.00	124.00	133.00	145.00	154.00
Fixed O&M Costs (early '86 $/kw-yr)	4.92	4.98	5.00	5.45	5.74	6.11	6.39
Variable O&M Costs (early '86 mills/kwh)	0.25	0.32	0.46	0.69	0.92	1.36	1.80
Energy Penalty (%)	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Capacity Penalty (%)	2.10	2.20	2.10	2.10	2.10	2.10	2.10
Reliability Penalty (%)	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Annual Emissions Rate (lbs. SO_2/mmBtu)	0.22	0.29	0.48	0.48	0.48	0.60	0.80

Electricity Demand Growth

Electricity demand growth is forecasted to be much lower (1.7 percent per year from 1987 to 2010) in the Low Case than in the High Case (2.6 percent per year from 1987 to 2010). This has readily apparent ramifications upon the amount of utility generation required to meet electricity demands, the majority of which is provided by fossil fuels. Thus, higher electricity demand growth ultimately translates to higher utility emissions.

The national average growth rate assumptions incorporated in these reference cases were implemented at EPA's direction. Differential growth rates by region were based on recent NERC projections of future electricity growth in each NERC reliability council region, and then adjusted by RCG/Hagler, Bailly, Inc. to achieve the target national sales growth rate assumed by EPA. In the High Case, however, somewhat different near-term growth assumptions (i.e., through 1995) were used in the East North Central and the West South Central regions. In this case, higher near-term growth was assumed in the East North Central (2.9% per year from 1987 to 1995 instead of 2.5% per year) reflecting a continuation of recent historical growth trends (about 3.3% per year from 1986 to 1988) and consistent with strong economic growth and low oil prices assumed in this case. In contrast, low near-term growth was assumed in the West South Central (1.9% per year from 1987 to 1995 instead of 2.9% per year) reflecting a continuation of recent historical trends (only 2% per year from 1985 to 1988) and consistent with low oil prices and, hence, sluggish growth in this region in the near term.

Since ICF forecasts of future regional electricity demand growth were previously the underlying source for

the EPA demand forecasts, regional sales growth patterns in the 1989 EPA Base Case analysis are different than those used in the 1987 EPA Base Case.

Repowering

In contrast to the 1987 EPA Base Case, EPA assumed for this Base Case analysis that utilities would undertake a small to significant amount of repowering at certain existing coal-fired units. Repowering (using a "generic clean coal" technology) was assumed at EPA's direction to have much greater market penetration in the Low Case than in the High Case. Repowering candidates were assumed to include only those unscrubbed SIP coalunits greater than 75 megawatts and less than 400 megawatts, since current evidence suggests that repowering technologies may be uneconomic or technically infeasible at very small or very large units. Units were assumed to become part of the candidate pool upon reaching 35 years of age beginning in 2000 (with only units built before 1950 assumed to be too old to repower).

In the Low Case, it was assumed a total of one third of all such candidates would repower by 2010 with lower percentages (5 percent by 2000 and 20 percent by 2005) assumed in earlier years. In the High Case, much lower market penetration was assumed with only 10 percent of candidate units repowering by 2010 (5 percent by 2005 and no repowering in 2000).

In the assumed first year of repowering in both the High and Low Cases, units between 75 and 150 Mw and built before 1960 were generally selected for repowering. In later years, units up to 400 Mw and those built in the late 1960s and early 1970s were assumed to be selected for

repowering. Smaller units were assumed to be selected first because utilities would wish to develop their design and construction expertise in simpler, less expensive settings. Older units were selected first because they are generally smaller and because many utilities would tend to repower units as they reached the end of their useful lives (assuming no major refurbishment). Repowered units were selected regionally so as to roughly reflect the proportional distribution of available candidate capacity. (A list of selected repowered capacity by CEUM regions is included in Appendix C.) Future utility regional capacity requirements (as forecast in the two reference cases) were taken into account in selecting the repowered units. Capacity was only selected to the extent new capacity was needed in the region to meet reserve margin requirements.

Note that capacity affected by these repowering assumptions are in addition to those units which have already repowered (e.g., TVA's Shawnee 10, NSP's Black Dog 4, MDU's Heskett 2, Colorado-Ute's Nucla 4) or have firm plans to repower (AEP's Tidd and Sporn projects, SPS's Nichols 3). Together, these units total roughly 1 gigawatt of capacity, in contrast to about 38 gigawatts of repowered capacity that results by 2010 from the repowering assumptions of the Low Case.[3]

The assumed cost and performance characteristics of the repowering technology are discussed below, and are generally representative of a fluidized bed combustion (FBC) technology.

[3] In addition, other projects (using other emissions control technologies which do not increase capacity) that were approved for funding in DOE's Clean Coal Technology development program (through Round II) were also included in this Base Case analysis.

- *Capacity* at those units that were selected for repowering was assumed to increase by 50 percent upon repowering. DOE assumes that atmospheric FBC (AFBC) repowering would lead to a 15 percent increase in capacity, pressurized FBC (PFBC) repowering would lead to a 30-50 percent capacity increase, and integrated gasifier combined cycle (IGCC) repowering would lead to a 150 percent increase in capacity.[4] The 50 percent capacity increase assumption was thus chosen as a reasonable average capacity gain for repowering projects to reflect a "representative" repowering technology, weighted heavily towards FBC technology for a typical installation (given the current relatively advanced state of FBC development, demonstration, a economic refinement). This 50 percent average capacity gain assumption is in agreement with EPRI's current assumptions.

- A *heat rate* of 9500 Btu/kwh was assumed for all repowering projects. This is in rough accord with EPRI TAG estimates for the candidate repowering technologies (9000 Btu/kwh for PFBC and IGCC, 10000 Btu/kwh for AFBC).[5]

- *O&M cost* estimates for the generic repowering projects were also derived using EPRI TAG. information (see PFBC combined cycles). Assuming the use of a 4% sulfur bituminous

[4] *America's Clean Coal Commitment*. U.S. Department of Energy, Office of Fossil Energy, February 1987.

[5] *TAG – Technical Assessment Guide, Volume 1: Electricity Supply – 1986*. Electric Power Research Institute (EPRI p. 4463-SR), December 1986.

coal, fixed O&M costs were assumed to be $38.60/kw-ye, while variable O&M costs were assumed to equal 5.5 mills/kwh (costs in early 1986 $).

- A *minimum capacity,* (turndown) of 50 percent was assumed for repowered units also in line with EPRI's assessment of PFBC technology.
- Additionally, it was further assumed that repowering would not affect a unit's *availability* (forced and scheduled outage rates were assumed not to improve).
- *Emissions rates* were assumed to meet current NSPS requirements for SO_2 and TSP. NO_x rates from repowered projects were assumed to equal 0.3 lbs. NO_x per million Btu.

Note that the assumed level of repowering can significantly affect new utility capacity needs/decisions, regional coal production, and the level of SO_2 emissions (since repowered units have much lower SO_2 emissions rates).

New Unplanned Coal Capacity

No new unplanned coal capacity was assumed to be built until 2000 (High Case) or 2005 (Low Case) to reflect the difficulties and long lead times in planning/siting/building new coal plants. This assumption influences coal versus gas capacity and consumption levels, as well as coal production levels and SO_2 emissions forecasts.

Renewable and Non-Traditional Capacity and Generation

In the High Case, a small amount of planned renewable and non-traditional capacity was assumed to be added by 20 (about 5 gigawatts, with most being added in California). After 2000, in the High Case, no additional non-fossil capacity was assumed to be added. In contrast, in the Low Case, a significant quantity of new currently unplanned renewable and non-traditional capacity was assumed to be added by utilities after 2000. This was assumed to include such possibilities as advanced nuclear, wind, solar, and geothermal technologies. The amount of such capacity was assumed to be sufficient to meet approximately one-quarter of all assumed incremental electricity demand growth after 2000. The effects of this assumption are to reduce new fossil capacity requirements, lower fossil fuel consumption, and decrease utility SO_2 and NO_x emissions.

Cogeneration

The effects of the assumed higher cogeneration forecasts in the Low Case are similar to the effects of increased renewable and non-traditional capacity. The cogeneration assumptions used in the Low Case were developed by RCG/Hagler, Bailly, Inc. The High Case cogeneration assumptions were developed by ICF from recent assessments conducted in preparing the FERC Base Case.[6] Although the High Case cogeneration forecasts

[6] *Draft Environmental Impact Statement: Regulations Governing Independent Power Producers (RM88-4-000) and Regulations Governing Bidding Programs (RM88-5-000)*, Federal Energy Regulatory Commission,

(Continued on following page)

are lower than those used in the Low Case, both sets, of assumptions result in more cogeneration than assumed in the 1987 EPA Base Case. This results in less utility generation and, hence, lower emissions.

Powerplant Lifetimes

Powerplant lifetime assumptions also have significant effects upon forecasted SO_2 emissions. Shorter assumed fossil powerplant lifetimes serve to lower SO_2 emissions forecasts, since older high-emitting units would retire sooner (and be replaced by lower-emitting new capacity). Further, regional coal production patterns are potentially affected, since retiring low- or medium-sulfur coal units might be replaced by new scrubbed coal capacity using high sulfur coals. In contrast, longer assumed nuclear lifetimes would lower SO_2 emissions by delaying the need for fossil-fired replacement capacity.

The range of assumptions for large fossil plants (65 years assumed in the High Case, 55 years assumed in the Low Case) was specified by EPA. EPA in the past has used a 60 year lifetime assumption. Note that smaller units (under 50 megawatts) are assumed to retire sooner (after 45 years) to reflect generally unfavorable economies of scale in refurbishing low capacity units. The range of assumptions for nuclear plants (35 years in the High Case and 40 years in the Low Case) was also specified by EPA. Nuclear plants are granted a 40-year operating license upon issuance of their construction permit (for plants built prior to 1982) or upon issuance of their operating license

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Offices of the General Counsel, Office of Economic Policy, Office of Electric Power Regulation, June 1988.

(for plants built in 1982 or after). Thus, most pre-1982 plants would only have lifetimes of about 35 years or less from date of initial operation (because of the lag between licensing, construction, and final operation). However, the NRC has recently changed the terms in two cases such that the duration of the permit is from the date of initial operation, which would result, in an effective 40-year lifetime. Accordingly, the range of nuclear plant commercial lifetimes is most probably bounded by a low of 35 years and a high of 40 years.

Coal Mining Productivity

Coal mining productivity assumptions were revised for this Base Case analysis to reflect recent continued high productivity growth in the coal mining industry. For instance, gross labor productivity increased by about 7 percent per year between 1982 and 1987 at underground mining operations. While ICF views these high rates of productivity growth as a short-term phenomenon, the high rates of growth in the past few years (and expected in the near future) were newly incorporated into this Base Case analysis, and have important implications on coal prices: real coal prices (and sulfur premia) are lower in these reference cases than in the 1987 EPA Base Case. The net effect of higher assumed mining productivity is thus to make coal more economically attractive (by reducing the future trends in real coal prices) in new capacity decisions.

Emissions Rates and Limits

A recent review of SO_2 emissions rates at selected powerplant units around the country revealed that some units (including many unscrubbed NSPS Subpart D units

in the West) have historically emitted, and will likely continue to emit, at rates well below their required limits. Generally, this is because these units have access to ample supplies of inexpensive local coals, or have committed to contract purchases of coals, which have sulfur contents well below SIP or NSPS requirements, or have found that the variability of sulfur in coals requires a lower long-term average sulfur content. For the new Base Case analysis, these units were assumed to emit at rates in line with current coal deliveries

As a result of (1) the recent enactment, revisions to, or implementation of acid rain programs in certain states (Minnesota, Wisconsin, Massachusetts, New Hampshire, and New York), and (2) latest revisions in SIP limits due to stack height or local ambient air quality reviews (particularly in Indiana), several unit-specific, utility-specific, or statewide emissions limits were included for this new EPA Base Case analysis. These regulatory changes have occurred since the development of the 1987 Base Case in late 1986. No other changes in emissions limits were assumed by EPA. It was assumed by EPA that the recent WEPCo decision would not result in any significant number of powerplants having to comply with NSPS upon refurbishment.

Financial Parameters

Electric utility financial assumptions are presented below and were not varied under the two base cases. They differ slightly from the 1987 EPA Base Case with the real cost of capital somewhat higher but the real capital charge rate about the same. The major difference in the real cost of capital was the assumed cost of debt, preferred equity,

and common equity. These were raised to levels of 9.2 percent pre-tax cost of debt, 10 percent cost of preferred equity, and 13 percent cost of common equity (based on current nominal cost of debt and preferred equity for utilities) from previous assessments of 7.6, 7.9, and 12.8 percent respectively. Note that for future investments this cost of capital could be higher or lower although long term real cost of debt and equity have generally been much lower. EPRI assumes somewhat higher nominal cost of debt and equity which largely reflects a higher assumed inflation rate of 6 percent.

	Percent of Total Utility Capital	Pre-Tax Cost	After Tax Cost	Mixed Weighted Average Cost
Debt	50%	9.2%	5.61%	4.60
Preferred Equity	15%	16.39%	10.0%	1.50
Common Equity	35%	21.31%	13.0%	4.55
				10.65%

Nominal Discount Rate	10.65%
Real Discount Rate	5.38%
Inflation Rate	5.0%

Real Capital Charge Rates

30 Year Book Life: Coal/Nuclear/Scrubber/ Combined Cycle	9.4%
20 Year Book Life: Combustion Turbines	11.5%

Nuclear Capacity and Capacity Factors

Nuclear capacity was not assumed to vary between the two base cases. No new nuclear capacity beyond

currently planned units was assumed to be built by 2010 in the High Case. In the Low Case, as part of increased non-fossil generation assumptions, it was implicitly assumed that new nuclear plants could potentially be built *after* 2000. In both cases, in the near term, several important assumptions were made regarding the completion of delayed units: Seabrook will be at full power by 1995, Shoreham will be cancelled and remain unused, and Rancho Seco will continue to operate for the duration of its life. In addition, Vogtle 2 (Georgia Power), Limerick 2 (Philadelphia Electric), Comanche Peak 1 and 2 (Texas Utilities), South Texas 1 and 2 (MAP), and all TVA units except Watts Bars 2 and Bellefonte are assumed to be on-line by 1995; Watts Bar 2 will be on-line by 2000, and Bellefonte will be cancelled.

Average nuclear capacity factors have been increased in the near-term compared with the 1987 EPA Base Case (70 percent versus 67 percent in 1995). In the new reference cases the capacity factor was also increased in 2000 (71 percent versus 67 percent in 2000). The higher capacity factors in 1995 and 2000 reflect better operational practices instituted in, recent years and a continuation of improvements experienced in the last several years (e.g., historical capacity factors in the U.S. have increased from recent low levels of 57 percent in 1986 to 65 percent in 1988). After 2000, as many units age, average capacity factors are assumed to decline to about 66 to 68 percent as unit reliability decreases.

EXHIBIT 41

ICF RESOURCES
INCORPORATED

Mr. Robert A. Beck
Director
Clean Air, Fossil Fuels and
Natural Resources
Edison Electric Institute
1111 19th Street, N.W.
Washington, D.C. 20036

July 26, 1989

Dear Mr. Beck:

In your letter of July 12, 1989, you raised a number of questions regarding the assumptions used in the 1989 Base Case analyses performed by ICF Resources for EPA. We are happy in this letter to respond to these questions. In addition, we have enclosed a copy of the report *1989 Base Case Forecasts* for your use and review.

The 1989 EPA Base Case analyses were conducted by ICF for EPA's Office of Policy, Planning and Evaluation to reassess future utility air emission trends using up-to-date sets of assumptions. In the Base Case analyses, EPA had us examine two cases – a "High" case and "Low" case – so as to present a reasonable possible range of future utility emissions. To achieve this result, these cases incorporated different sets of assumptions that would respectively result in higher and lower utility SO_2 emissions trends.

Fossil powerplant lifetime assumptions were among the important differences in assumptions between the two cases: 55 years was assumed for all large (i.e., larger than 50 megawatt) fossil steam generating units in the Low case, while 65 years was assumed for all large fossil steam units in the High case. The difference in assumptions

obviously has an important effect on utility emission trends, as demonstrated in the ICF analysis. Before 1984, EPA had assumed that all fossil-fueled powerplants had a physical, useful operating lifetime of 45 years for al of the analyses performed by ICF for EPA. This assumption was subsequently revised to 60 years for the 1984 Interim EPA Base Case and all following analyses as it became obvious that existing powerplants were being operated for periods longer than 45 years.

For both of the cases evaluated for the 1989 EPA Base Case forecasts, it was assumed that all large oil- and coal-fired powerplant units at 30 years of age would engage in refurbishment activities sufficient to achieve the above-noted powerplant lifetime assumptions. Those units explicitly assumed to repower using a "generic clean coal" technology were not included as part of this universe of "life extended" powerplants. About 350 gigawatts of capacity (about half of all fossil fuel-fired capacity expected to online by 2010) will undertake life extension activities by 2010 under these specific assumptions.

Consistent with previous ICF modeling efforts, it was assumed that net dependable capacity and reliability of existing powerplants would be maintained at design levels for their entire 55 to 65 year lifetime. However, unit heat rates were assumed to increase by 0.25% per year to reflect powerplant aging (i.e., to reflect progressive deterioration in potential power output, combined with a one-time 5% decrease in heat rates assumed to occur at the time of refurbishment (to reflect the restoration of the powerplant to something close to its original design operating efficiency as a result of refurbishment). These assumptions have been included in all of the EPA analyses

by ICF since the 1985 EPA Base Case assessments began in 1984.

Two additional issues related to powerplant refurbishment that were raised either directly or implicitly in your letter include the following:

- The powerplant lifetime/refurbishment assumptions in the 1987 Interim EPA Base Case included an assumed average cost of $200 per kilowatt in early 1986 dollars for all refurbished units. No assumptions regarding the costs of refurbishment were explicitly made in the more recent analyses, however, because the costs of life extension were assumed to be sufficiently low (at $200 per kilowatt in early 1986 dollars or less) that all units would be refurbished and their lives extended under all the environmental regulatory scenarios evaluated. Since these refurbishment costs will be incurred in all cases, they do not affect the analysis of different environmental regulator scenarios.

- As stated on page 29 of the enclosed report, "it was assumed by EPA that that recent WEPCo decision would not result in any significant number of powerplants having to comply with NSPS upon refurbishment." It was also assumed that refurbishment would not result in more stringent emission requirements under PSD. Thus, for purposes of the recent EPA forecasts, the act of refurbishment, (which, for the purposes of the EPA Base Case, means efficiency improvements and other maintenance designed to enable an additional 25-35 years of acceptable operation up to design capacity) was not assumed by EPA to require any refurbished plant to meet tighter new source emission controls.

We hope that this information is useful to you and adequately addresses your questions. Please call should you have any further questions.

Sincerely,

SIGNED BY K.A. SCHWEERS
Kenneth A. Schweers, President
ICF Resources Incorporated

EXHIBIT 42

United States General Accounting Office

GAO	**Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives**
September 1990	**ELECTRICITY SUPPLY** **Older Plants' Impact on Reliability and Air Quality** [SEAL]

GAO/RCED 90-200

Chapter 3

Changing Air Quality Requirements Could Affect Life Extension Plans

Fossil fuel power plants are significant sources of harmful pollutants, particularly sulfur dioxide and nitrogen oxides, and the plants exempted from the Clean Air Act produce a disproportionately large share of these pollutants. Recent legislative and regulatory developments could require significantly reduced emissions from these exempt plants and could cause electric utilities to alter some planned life extensions projects. Enactment of proposed acid rain control legislation probably would not preclude life extension, but this depends on the legislation's final requirements. Officials of DOE and utility organizations expressed concern, however, that exempt plants altered to extend their service life must meet the act's emission standards if EPA decides, as it did for one plant in 1988, that the alteration would result in increased emissions. According to the officials, the additional costs of achieving the more stringent standards

could discourage some life extension projects. However, such decision one plant in 1988, that the alteration would result in increased emissions. According to the officials, the additional costs of achieving the more stringent standards could discourage some life extension projects. However, such decisions could also reduce the nation's total power plant emissions by eliminating an existing economic incentive to retain exempt plants.

Plants Constructed Before August 1971 Produce the Most Pollutants

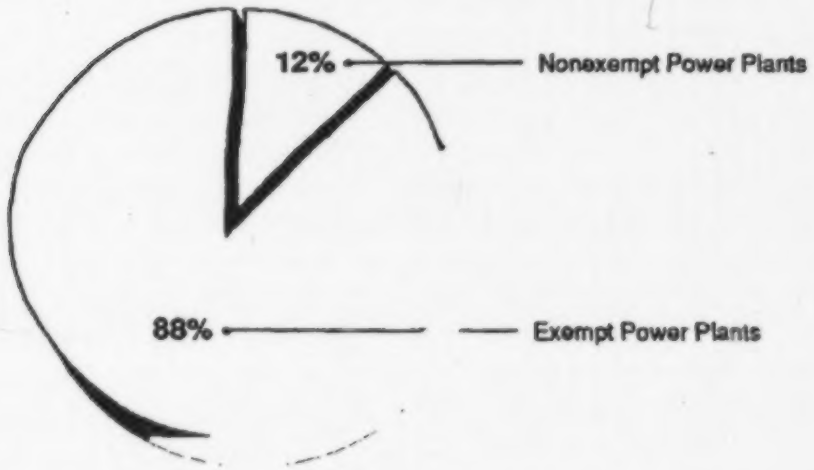
When Congress enacted the Clean Air Amendments of 1970, it exempted power plants constructed prior to the publication of EPA's regulations (August 17, 1971) from having to meet the legislated emission standards. The exempt plants produce a disproportionate share of utilities' sulfur dioxide and nitrogen oxide emissions.[1] Although these plants that were exempted from federal regulations are subject to state regulations, the states generally allow emissions at much higher levels than those specified in the Clean Air Act.

Emissions of sulfur dioxide and nitrogen oxides have associated health and environmental consequences. Sulfur dioxide, a colorless gas with a pungent and irritating odor, can aggravate symptoms of heart and respiratory diseases. Nitrogen oxides, gaseous air pollutants, can also aggravate respiratory problems. Emissions of sulfur dioxide and nitrogen oxides, which have been linked to the formation of acid rain, also represent a threat to natural resources, ecosystems, materials, and visibility.

[1] Burning fossil fuel also produces air pollutants such as particulate matter and carbon dioxide, but because the current Clean Air Act debate relating to utilities focuses on acid rain controls, our analysis was limited to sulfur dioxide and nitrogen oxides.

According to EPA's nationwide data for 1985,[2] the last year for which complete data are available, plants' built prior to August 1971 contribute the majority of fossil fuel plants' emissions of sulfur dioxide and nitrogen oxides. In 1985 fossil fuel power plants emitted 16 million tons of sulfur dioxide; plants built prior to August 17, 1971, emitted 88 per cent of the total (see fig. 3.1). Of the nearly 7 million tons of nitrogen oxides emitted in 1985 by fossil fuel plants, approximately 79 percent was emitted by the exempt plants (see fig. 3.2).

Figure 3.1: 1985 Sulfur Dioxide Emissions by Exempt and Nonexempt Fossil Fuel Power Plants



Note: Total 1985 sulfur dioxide emissions from electric utility fossil steam power plants were 16,046,190 tons.

Source: Prepared by GAO from EPA data.

[2] The data, from EPA's Air and Energy Engineering Research Laboratory, are not measurements of actual pollutants released into the atmosphere, but EPA's best estimates.

* * *

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Application of the Clean Air Act's Current Emission Standards to Plants With an Extended Service Life Is Uncertain

In developing regulations following the 1977 Clean Air Act amendments, EPA assumed that utilities would continue to replace most plants at the end of their traditional 30- to 40-year service life; consequently, the regulations do not explicitly address power plant life extension. In a 1988 case, the agency ruled that the Clean Air Act's emission standards would apply to a previously exempt power plant if the utility would pursue its life extension project as proposed. This ruling has created concern among DOE and electric utility organization officials regarding the potential costs, and therefore the economic viability of some life extension projects.

Clean Air Act Regulations Do Not Explicitly Address Life Extension

In enacting the Clean Air Act Amendments of 1977, Congress revised the New Source Performance Standards (NSPS) and established the Prevention of Significant Deterioration (PSD) program. The NSPS, established by Congress under Clean Air Amendments of 1970, regulate the emissions from new sources, including electric utility power plants. The standards were modified in 1977 to further restrict power plant emissions by requiring the use of emission control technology, typically flue gas desulfurization (FGD) equipment for reducing sulfur dioxide emissions, and other types of emission control equipment for reducing emissions of other regulated pollutants. The PSD program was established to preserve air quality in unpolluted areas

of the country by regulating power plants' total annual emissions and, as the NSPS do, by requiring the use of the "best available" emission control equipment. EPA, in formulating the NSPS and the PSD program, included provisions regulating modifications of power plants, but because it did not anticipate life extension, it did not explicitly address life extension projects.

While Congress exempted plants constructed prior to the enactment of the new emission standards, it also instructed EPA to apply the standards where EPA determines a plant has been "modified." In amending the act in 1970, Congress defined a modification as a physical or operational change to an existing facility resulting in an increase in the emission of any controlled pollutants or of pollutants not previously emitted. The NSPS are triggered by any change that increases the hourly emission rate for any controlled pollutant. The PSD program provisions are triggered by any change that increases the total amount of annual emissions for any controlled pollutant. EPA also applies the new emission standards in cases where it determines a plant has been "reconstructed" – a determination applicable if the cost of the alteration exceeds 50 percent of the cost that would be incurred to construct a comparable new facility.

The regulations regarding power plant modifications contain exemptions allowing utilities to undertake certain routine activities that could increase emissions without making the plant subject to either the NSPS or the PSD program. These activities include routine maintenance, routine repair and replacement of equipment, and certain operational changes, such as increasing the hours of operation in response to a higher demand for electricity.

Life Extension Projects May Constitute Modifications or Reconstructions

Power plant life extension projects involve physical or operational changes to power plants that potentially can invoke either the modification or reconstruction provisions and thus trigger the NSPS and the PSD program provisions. In recent years, EPA, DOE, and the utility industry recognized the potential for these projects to invoke either the modification or reconstruction rules.

In March 1986 members of EPA's policy analysis staff noted the trend toward power plant life extension and its adverse effect on attempts to reduce sulfur dioxide emissions.[3] Explaining ways in which plants undergoing life extension might be required to achieve the NSPS and the PSD program provisions, the article suggested, for example, that the reconstruction rule might be revised or that all power plants over 30 years of age could be required to achieve the NSPS and the PSD program provisions.

Various DOE and industry studies of life extension and guidelines for implementing life extension programs also have noted that the modification or reconstruction rules might be invoked by life extension projects thus making previously exempt plants subject to the requirements of the NSPS and the PSD program. These documents suggested that utilities planning life extension projects should incorporate into their decision process the possibility of having to meet stricter environmental standards. In 1987

[3] DeMocker, Greenwald, and Schwengels, "Extended Lifetimes for Coal-fired Power Plants: Effect Upon Air Quality," *Public Utilities Fortnightly* (Mar. 20, 1986).

EPRI noted that plant life extension projects involve the risk that the NSPS could be applied.[4]

In September 1988, after the Wisconsin Department of Natural Resources asked for EPA's review of the Wisconsin Electric Power Company's (WEPCO) proposed life extension project. EPA determined that the project would constitute a "modification" under the act and that the plant, if altered as proposed, would be required to meet the act's more stringent emission standards. This decision was the first instance of EPA's requiring a plant undergoing life extension to achieve the NSPS and the PSD program requirements. EPA's ruling was based on a determination that (1) the proposed changes to the power plant would go beyond "routine repair" and would therefore not be exempt and (2) emissions would increase as a result of the project.

The utility challenged EPA's definition of routine repair and its method for calculating increases in emissions. Following litigation in January 1990 the United States Court of Appeals for the Seventh Circuit affirmed EPA's application of the NSPS, but remanded the decision to apply the PSD program standards back to EPA for further review. Specifically the Court held that in this instance, the proposed changes were not routine and thus not exempt from the standards and that an increased emission rate would result; thus, EPA had correctly applied the NSPS. However, the court ruled that EPA had not used an appropriate method for determining the total annual increase in emissions and instructed EPA to reexamine the application of the PSD program provisions. The Court added that EPA is entitled to broad

[4] John Douglas, "Longer Life for Fossil Fuel Plants," *EPRI Journal* (July/Aug. 1987)

discretion in interpreting the technical provisions of the Clean Air Act and its own regulations.[5]

Effects of WEPCO Ruling Are Uncertain

Officials of DOE and utility organizations have expressed concern that the WEPCO decision may result in EPA's application of the NSPS and the PSD program requirements to other previously exempt power plants and that the additional costs of achieving these standards and requirements could discourage some life extension projects. However, EPA officials do not consider WEPCO's project typical of most utility life extension projects, and they expect that the ruling will not significantly affect utilities' decisions to undertake power plant life extension projects.

According to NERC, the ruling could seriously threaten the reliability of the nation's electric system if it were applied to other life extension projects, as the additional cost for emission control equipment could force utilities to remove older plants from service. According to EEI, serious problems with the reliability of the electric system could be encountered, including brownouts, as utilities adjust their plans and pursue other sources of new generating capacity. The Utility Air Regulatory Group (UARG)[6] has expressed concern over whether power plants can be maintained properly without being required to achieve the more stringent emission standards. DOE has stated that EPA's WEPCO ruling could discharge some utilities from extending the service life of their power plants and that this could aggravate an expected shortfall in electric generating capacity in the 1990s.

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[5] *Wisconsin Electric Power Co. v. Reilly, AD. EPA*, 893 F.2d 901 (7th Cir. 1990)

[6] UARG is an ad hoc association of utilities and trade associations of the utility industry.

The frequent application of the NSPS and the PSD program requirements to previously exempt power plants or similar legislative action could improve air quality. During 1985 power plants exempt from the Clean Air Act's more stringent emission standards produced sulfur dioxide emissions at up to nearly 3 times the rate, per unit of electricity produced, of power plants subject to these standards. Because new power plants are subject to more stringent emission standards, there is an incentive to extend the life of existing plants that are not subject to these costly standards. If decisions similar to the WEPCO decision were rendered more often, a decision to build a new plant or extend the service life of an existing plant would depend on the relative costs of two sources emitting pollution at a low rate, and not on a comparison of the high cost of a new plant emitting pollution at a low rate and the lower cost of an older plant emitting pollution at a higher rate.

Officials from seven of the nine utilities we contacted indicated that the WEPCO decision was not interfering with their plans for the continued operation of their existing plants.[7] These officials explained that WEPCO's project involves the restoration of generating capacity at a deteriorated plant and that this situation is unlikely to occur in their systems because their maintenance programs prevent their plants from deteriorating. Officials from one of the nine utilities we contacted indicated that the WEPCO ruling has played a role in the utility's revising its plans. In its annual submission to its public utility commission, this utility explained that because of legislative and regulatory uncertainties (including the uncertainty raised by the WEPCO decision), it has deferred implementing a life extension program. However, the utility reported that it

[7] One utility did not respond to our questions about the potential impact of the WEPCO ruling on power plant projects.

will continue to maintain its plants to ensure their reliable and safe operation.

According to EPA policy officials, WEPCO's life extension project is not typical of the majority of utilities' life extension projects, and concerns that the agency will broadly apply the ruling it applied to WEPCO's project are unfounded. The officials noted that many life extension projects do not result in increased emissions, while other activities are routine in nature and thus exempt from the modification rule. Lending evidence to the officials' statements, EPA's 1989 emission forecast assumed that the WEPCO decision would not result in a significant number of additional power plants' having to comply with the NSPS and the PSD program requirements.

Supplying Electricity May Result in Short-term and Long-term Trade-offs

In the short term, utilities may face trade-offs between ensuring the existence of generating capacity sufficient to meet needs and reducing air pollution. More stringent emission requirements could adversely affect electricity supply in the short term. However, applying more stringent emission requirements to currently exempt plants would have the benefit of eliminating the power plants that pollute the most.

A trade-off between sufficient capacity and clean air need not exist in the long term. Requiring exempt power plants to meet the requirements of the NSPS and PSD program would result in emission reductions at existing plants or less-polluting new plants. The cost of reducing emissions would be reflected in the cost of producing electricity. The long-term trade-off could be between

cleaner air and more expensive electricity rather than between cleaner air and insufficient capacity.

* * *

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA, Plaintiff,	:	
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP Plaintiff-Intervenors	:	Civil Action No. 1:00 CV 1262
v.	:	
DUKE ENERGY CORPORATION, Defendant.	:	

Washington, D.C.

Wednesday, May 15, 2002

Videotaped, I-Dep Deposition of STEPHEN TIBER, a witness herein, called for examination by counsel for Defendant in the above-entitled matter, pursuant to notice, the witness being duly sworn by SUSAN L. CIMINELLI, a Notary Public in and for the District of Columbia, taken at the offices of Hunton & Williams, 1900 K Street, N.W., Washington, D.C. at 2:08 p.m., Wednesday, May 15, 2002, and the proceedings being taken down by Stenotype by SUSAN L. CIMINELLI, CRR, RPR, and transcribed under her direction.

* * *

[37] [Q.] . . . Let me ask you first when it uses words like EPA policy officials, who is it, what officials is it likely talking about?

A. These would be EPA employees in a policy capacity with whom GAO spoke.

Q. Would that have included Rob Brenner at that time?

A. According to what Dan Feehan, the GAO evaluator indicated, he spoke with Rob Brenner during the course of the review.

Q. Would Rob Brenner have been a policy official, and EPA policy official at that time?

A. I believe so.

Q. Let's assume that in your meetings in April of 1990 that EPA representatives told GAO that GAO had some of the facts wrong here in the statement. Has that happened on other occasions?

MR. KAPLAN: Objection to the form.

BY MR. COTTINGHAM:

Q. Has that kind of thing happened?

A. The purpose of a meeting to discuss a statement of facts is to discuss the content of a [38] statement which might include misinformation, incomplete information.

Q. If the facts are incorrect and EPA tells GAO in those meetings that the facts are incorrect, is it normal for GAO to correct the facts before issuing its report?

MR. KAPLAN: Objection to the form. It's beyond the designation.

BY MR. COTTINGHAM:

Q. Go ahead.

A. GAO will revise the draft document if EPA can support its position.

Q. Going back to the statement on page 5 of the statement of facts, which says according to EPA policy officials, the WEPCO decision does not represent a broad EPA policy to control emissions from life extended power plants. Was that in fact a correct statement in 1990?

A. Again, I don't have supporting documents as to what was said at that time. I did speak with Dan Feehan about not this document but the report itself.

Q. Okay.

A. And he did discuss that he did remember talking with Rob Brenner when in the report the [39] document refers to – let's see, on – I didn't see this at the bottom of page 30. In the report, it says according to EPA officials.

Q. It says according to EPA policy officials?

A. Policy officials. Correct. I'm sorry. According to EPA policy officials, he remembers a meeting with Rob Brenner, among others, where they were giving their professional opinions based on information available at that time. They, he remembered that the EPA staff didn't offer, or didn't have or refer to documents that, that reflect this professional viewpoint.

Q. This is what Don Feehan told you?

A. Yes. Dan. Dan Feehan. Right.

Q. What else can you remember that Dan Feehan told you?

A. He told me that he lived in a number of cities while he was conducting this report. We didn't go into any great detail about it. Though, we were discussing this particular point, and I was asking him what he recalled about who the statement could be attributed to, and –

Q. You are talking about on page 30 where it says, According to EPA policy officials, WEPCO's life extension project is not typical of the majority of [40] utilities' life extension projects and concerns that the agency will broadly apply the ruling it applied to WEPCO's project are unfounded. And there is more after that.

A. Yes. Right. Right. It's that paragraph that we were discussing.

Q. You were trying to find out from Dan Feehan who gave him that information and what they told him?

A. Correct. Exactly. Exactly. And if there was any additional supporting information, you know, to support their case. Dan mentioned that if there were, that they would have referenced it in the report to support the statement. That's just standard GAO practice to support their findings.

Q. But his recollection is that Rob Brenner and others in a meeting told him what is written in the report on page 30 and 31?

A. Correct.

Q. So who else was in the meeting other than Dan Feehan and Rob Brenner where this information was conveyed?

A. Dan Feehan didn't recall the others.

Q. But there were other people from EPA in the meeting, correct? Or according to what Dan [41] Feehan remembers?

A. Correct. Dan indicated that there were others present.

Q. Right. And were there others from GAO present?

A. We didn't discuss that.

Q. Okay. Did you read this entire paragraph to Dan Feehan or discuss the entire paragraph, we were just reading the first sentence but it goes on to say the officials noted, and that's talking about the EPA policy officials, correct?

A. Yes. That is correct.

Q. The officials noted that many life extension projects do not result in increased emissions while other activities are routine in nature, and thus exempt from the modification rule. And that's part of what GAO was told by these EPA policy officials who Mr. Feehan remembers, including Rob Brenner?

MR. KAPLAN: Objection to the form.

BY MR. COTTINGHAM:

Q. Correct. Did you get that?

A. Sorry.

Q. That entire paragraph is what Mr. Feehan remembers the EPA policy officials, including Rob [42] Brenner, telling him, correct?

A. That is.

Q. The GAO report goes on in that paragraph that says, Lending evidence to the official's statements, EPA's 1989 emissions forecast assumed that the WEPCO decision would not result in a significant number of additional power plants having to comply with the NSPS and the PSD program requirements. Do you see that?

A. Yes.

Q. Did you discuss that additional support for the policy official's statements with Mr. Feehan?

A. I don't recall that we reviewed the last sentence, though what I do recall Dan mentioning was that Rob Brenner and others were giving their professional opinion of data that they knew at that time.

Q. Do you know what the EPA's 1989 emissions forecast is?

A. Since I'm not in that program and intimately aware with it, I don't know what the forecast was.

* * *

EXHIBIT 44

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

Jun. 19, 1991

Hono e John D. Dingell
Chairman, Subcommittee on
Oversight and Investigations
Committee on Energy and Commerce
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

Thank you for enclosing a copy of the Septemb . 1990 GAO report entitled "Electricity supply – Older Plants' Impact on Reliability and Air Quality" with your October 9, 1990 letter. Your letter raises several questions concerning the impact of older power plants' "life extension", on the reliability of electricity supply. Enclosed are responses to your questions.

If you have any further questions, please do not hesitate to contact us.

Sincerely yours,

/s/ for
William G. Rosenberg
Assistant Administrator
for Air and Radiation

Enclosure

cc: Honorable Charles A. Bowsher
Comptroller General, GAO

Question 1.

Please explain what measures (other than life extensions) will be used to meet "future demand". What will be the role of conservation and new plants?

Response 1.

The role of renewable resources and *especially conservation* in meeting *current demand* is significantly higher than 10 years ago, despite regulatory obstacles, inequitable incentives and insufficient research and development support. In fact, few conventional electric generation options can today compete with energy efficiency investment to meet future demand. Recent estimates suggest that energy demand can be halved by 2010 with a savings of over 4300 billion to the U.S. economy.

The cost-competitiveness of conservation and renewable resources will be further increased by the Clean Air Act Amendments of 1990 and assessments of environmental externalities. Preventing significant increments of pollution through energy efficiency can be an important supplement to "end of smokestack/scrubber" technologies.

In addition to lower capital costs, lower financial risks, high reliability and pollution prevention benefits, energy efficiency is achieved by *investing* in the operation and maintenance of the various energy-consuming sectors of the economy. Any improvements in energy productivity (increasing economic output with stable or declining

energy input) will simultaneously enhance national energy security and the international competitiveness of American business. Finally, the development of a competitive "efficiency and renewable resource industry" to compete with such German and Japanese initiatives will be another by-product of this quicker, cheaper, cleaner approach to future demand.

Question 2.

Are such (life) extensions going to be cheaper and less time consuming with the enactment of title I of the Clean Air Act bill, S. 1630? Please explain.

Response 2.

Title I does not have much direct bearing on life extension projects. New source review is only implicated by life extension projects to the extent that they increase emissions and are thus considered modifications under Part C or D. As discussed in the answer to question 5, companies have and use discretion in project design and permitting to avoid increasing emissions and triggering the modification provisions. However, even if they could not or did not "net out" of new source review, power plant modifications would not face any significantly different treatment under the amendments in SO_2 or PM-10 nonattainment areas. Of course, if, due to a SIP call in a nonattainment area the state required the power plants to reduce their emissions, presumably the state would apply such a requirement to existing sources without regard to whether they were undergoing modification. In that case the cost of pollution controls would be attributed to the nonattainment program rather than the new source review program.

In ozone nonattainment areas where major stationary sources of NOx would be required to meet the same requirements as major stationary sources of VOC, under Section 182(f) of the amendments; power plants would be subject to the RACT provisions. Power plants undergoing a covered modification (under the new source review program) would have to achieve LAER instead. Like all major stationary sources in these areas, they would also have to procure offsets at the ratios stipulated for the various nonattainment severity categories. The cost of NOx offsets (if they were required) would thus increase the cost of a modification.

Question 3.

Please discuss in greater detail the "reliability of the electricity supply" from life extensions, taking into account the "different approaches to life extensions" discussed in the GAO report. Is there reason to be concerned about the reliability of these plants in meeting demand? Please explain. If they are not reliable, what are the contingencies?

Response 3.

EPA has not looked into the issue of "reliability of electricity supply" from life extensions.

Question 4

Do you agree with the demand figures? What are the real and timely alternatives to life extension to meet this anticipated demand?

Response 4.

The demand figures are included in a statement, quoted below, that appears on page 8 of the GAO report.

> The Department of Energy (DOE) and industry experts predict that demand for electricity will increase through the 1990s, outstripping planned additions to generating capacity. In 1989 the nation's total electric generating capacity was about 684,000 megawatts (MW). DOE projects a need for an additional 102,000 MW capacity by the year 2000, and utilities have made plans to construct plants that will produce only about one-third of this additional amount. Also, in 1989 the North American Electric Reliability Council (NERC) projected that utilities' planned additions would be insufficient by 1998. Moreover, according to NERC, some areas of the eastern United States will be at serious risk of supply disruptions in the early 1990s if the demand for electricity reaches the high end of the organization's forecast.

First of all, it is important to note the distinction between the capacity supply and capacity demand estimates. Increase in electric demand (in gigawatts) between 1989 and 2000 refers to the increase in annual peak demand by 2000. Increase in "capacity demand" is defined to include the change in peak demand plus a planning or required reserve margin. The increase in generating capacity needed (or "capacity supply") estimates reflect the difference between current (1989) electric generating capacity estimates (including cogeneration and imports) and future capacity needs (which are assumed to equal the "capacity demand" estimates). Because there is excess capacity in some areas of the country today, the required

increase in supply will be less than the forecasted increase in demand. *The DOE statement cited by GAO appears to refer to a required increase in capacity supply and the NERC forecasts refer only to capacity demand (as well as planned capacity additions).*

Growth in capacity demand (1989-2000) forecasted by NERC and adjusted for 2000 is about 207 gigawatts, and falls within the range forecasted in the EPA high and low base cases for the new acid rain provisions in the Clean Air Act (about 138-213 gigawatts). *EPA agrees with the NERC demand capacity figure.*

The increase in generating capacity supply needed (1989-2000) cited by GAO as DOE's forecast is 102 gigawatts. This is less than assumed in the EPA base cases. Note however, according to DOE/EIA "1990 Annual Energy Outlook", the increase in capacity supply needed was forecasted to be 186 gigawatts, which is in the upper end of the range assumed in the EPA base cases. *So EPA is unsure of GAO's statement regarding DOE's forecast of 102 gigawatts.*

Question 5.

I am uncertain about this EPA comment as reported by EPA. I can read it several ways, particularly with the word "significantly." What does EPA intend or mean? What is DOE's view? How will WEPCO affect acid rain legislation plants? Please explain. What is the Administration doing to clarify the matter? To what extent is the matter fully in EPA's control? What legal or other challenges are possible or likely? What relevant interpretative rulings has EPA issued or planned? What is their legal effect? How are they helpful? Please consider in your reply the

enclosed letter from the National Independent Energy Producers.

Response 5.

Some background on the NSPS and PSD programs and the life extension project at WEPCO's Port Washington, Wisconsin facility, may be helpful to respond to these questions. As noted in the GAO report, Congress dictated that modifications at existing plants be treated as new sources for purposes of the NSPS and PSD (as well as nonattainment new source review) provisions of the Clean Air Act. The Act defines modification as: 1) a physical or operational change that 2) increases emissions. Under the NSPS program, emissions increases are measured in terms of hourly potential emissions, while PSD considers increases in annual actual emissions. EPA's regulations contain several limitations on the broad statutory language, including, for example, an exemption, for routine changes.

In addition, EPA regulations contain broad "netting" provisions that enable source owners to offset emissions increases with equivalent reductions and thereby avoid the applicability of new source emissions standards or BACT limits. Under NSPS, netting may occur within the affected facility (e.g., an individual utility boiler) and involve physical restrictions on emissions capabilities (such as addition of pollution control equipment). Under PSD and nonattainment area new source review, netting may occur within the entire plant and may involve operational as well as physical restrictions on the plant's emissions.

Prior to the *WEPCO* court decision, EPA applied a "current actual" to "future potential" test to all nonroutine

changes at existing plants in determining emissions increases under the PSD bubble rule. That is, EPA assumed initially that following the changes, the plant would operate at its full potential to emit. Source owners could – and frequently did – avoid PSD applicability, however, through legally binding physical or operational limitations restricting actual emissions to levels not significantly greater than levels prior to the change. The owner would estimate the source's actual emissions following the change. If the owner projected that the source likely would not increase its actual emissions following the change, it would accept an actual emissions "cap." However, if the projection later proved inaccurate, and the owner desired to increase the source's actual emissions, it would need to obtain a new source permit at that time. As a result of the *WEPCO* court decision, modifications involving "like-kind" replacements, such as the WEPCO life extension project itself, now will be able to use a "current actual" to "future actual" test for PSD applicability purposes. In essence, this means that EPA, rather than the source owner, is responsible for accurately projecting a plant's actual emissions following a modification to determine whether the plant's emissions are within the bubble. If EPA projects no actual emissions increase, the source's emissions would not be legally capped.

Regarding WEPCO's life extension project, due to age-related deterioration and loss of efficiency, both the physical capability and actual utilization of the WEPCO power plant had greatly declined over time. The project involved the replacement of major internal components at all five of WEPCO's existing coal-fired steam electric boilers at its Port Washington plant. This project would restore the physical and economic viability of the existing powerplant

and extend its useful life for approximately 20 years. In its decision regarding WEPCO, EPA determined that the physical changes contemplated by the proposed project were nonroutine in nature and consequently were not categorically excluded from PSD or NSPS modification requirements. As indicated in the GAO report, it is expected that most utility projects will *not* be similar to the WEPCO situation. That is, EPA believes that most utilities conduct an ongoing maintenance program at existing plants which prevents deterioration of production capacity and utilization levels. To the extent that life extensions at such plants involve only an enhanced maintenance program, new source requirements may not apply for two reasons. First, the life extension may involve no nonroutine physical or operational change. If so, it would be excluded from new source provisions for that reason alone. Even if the life extension did involve nonroutine changes, it still would not trigger new source requirements if it did not increase pollution on an hourly basis (for NSPS purposes) or an annual basis (for PSD and nonattainment new source review purposes). It should also be noted that WEPCO is *not* a Clean Coal Technology or repowering project, nor is it (1) being implemented to comply with Title IV or any other Clean Air Act requirements, or (2) a basis (for PSD and nonattainment new source review purposes). It should also be noted that WEPCO is *not* a Clean Coal Technology or repowering project, nor is it (1) being implemented to comply with Title IV or any other Clean Air Act requirements, or (2) a voluntary pollution control project or research project of any kind. EPA's *WEPCO* decision only applies to utilities proposing "WEPCO type" changes, i.e., nonroutine replacement that would result in an actual emissions increase. This is the

basis for the EPA statement that the ruling is not expected to significantly affect power plant life extension projects.

In addition, it is important to point out that GAO was incorrect in its formulation of the choice that utility companies actually face. GAO stated that the utility company judgment on whether to build a new plant or instead to extend the service life of an existing plant depends on the relative costs of "two sources emitting pollution at a low rate, and not on a comparison of the high cost of a new plant emitting pollution at a low rate and the lower cost of an older plant emitting pollution at a higher rate." In fact, as explained above, due to EPA's netting rules, the owner of an existing source almost always has the choice of merely avoiding *increases* in emissions at existing plants, and is *not* required to meet the stringent emissions limits that apply to wholly new sources. Thus, using the nomenclature of the GAO report, the utility's choice is indeed between a new, "lower" emitting plant and an older, "higher" emitting plant. The only condition EPA has ever placed on the latter option is to insist that the source owner prevent the older plant from emitting at even higher levels.

EPA recently proposed a rule (copy enclosed) that would revise the agency's Prevention of Significant Deterioration (PSD) and nonattainment New Source Review regulations for the addition, replacement or use of pollution control projects (a project undertaken at a utility unit to reduce emission) at existing electric utility steam generating units. Changes that occur at a source that are intended to restore capacity or to improve the operational efficiency of the facility are not considered to be part of a pollution control project for purposes of this proposal. The proposal would not include pollution control projects as

modifications, unless the reviewing authority determines that the project will render the unit less environmentally beneficial. Until the proposal is final, EPA will continue its current policy of determining of pollution control projects are excluded from NSR on a case-by-case basis. The implementation of the proposed rule should not cause any negative environmental effects.

EXHIBIT 58

IN THE UNITED STATES DISTRICT COURT FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP	)	Civil Action No. 1:00 CV 1262
Plaintiff-Intervenors,	)	
v.	)	
DUKE ENERGY CORPORATION	)	
Defendant	)	

DECLARATION OF RICKEY J. DEESE

I, Rickey J. Deese, being of legal age and pursuant to 28 U.S.C. § 1746, declare:

1. I am General Manager of Technical Services in the Fossil-Hydro Division of Duke Power ("Duke"), the regulated arm of Duke Energy Corporation which has the responsibility of providing electric power to customers in portions of North Carolina and South Carolina. I am submitting this declaration based on my own personal knowledge and belief in support of Duke Energy Corporation's brief in support of its motion for summary judgment.

2. Duke and its predecessor entities have provided electricity to the Carolinas since the early 1900s. Duke's generation portfolio currently includes nuclear, hydroelectric, gas-fired combustion turbine, and coal-fired generating units. Duke has 30 coal-fired electric generating units at 8 plants located throughout North Carolina and South Carolina.

3. Duke's fleet of coal-fired electric generating units have an established history of operation, having been placed in service between 1940 and 1975. A list of these units, their operational dates, and their net rated generating capacities is found at attachment A hereto.

4. The boilers on these units are large, building-like structures – ranging from 6 to 20 stories high – that contain thousands of steel tubes in which water is heated to superheated steam with temperatures in excess of 900°F. These tubes are typically found in collections of tube assemblies, including the economizer tubes, where water is initially heated; the furnace waterwall tubes, where the water begins a phase change into steam; the superheater tubes, where the temperature of the steam is raised just before it exits the boiler and reaches the turbine; and the reheater tubes, where steam from the turbine is reheated and returned to the turbine. The furnace waterwall tubes form the walls of the boilers, and provide an envelope for coal combustion while also absorbing heat.

5. The boilers create steam by burning coal. Coal is ground to fine powder in pulverizers and moves through pipes to burners along the boiler walls. When the grounded coal is ignited in the furnace, "flue gas" is created with temperatures of up to 3000°F. The flue gas, which contains sulfur dioxide ("SO_2"), ash particles or particulate matter

("PM"), and nitrogen oxides ("NO_x"), passes around the tubes and tube assemblies. Water in the tubes becomes steam, which is then heated to superheated steam. Once the flue gas passes through the boiler, it is treated for emissions and then exits through a stack.

6. The superheated steam then enters the turbines; there it spins the turbine rotors, which are connected to a generator. The generator transforms the mechanical energy of the spinning rotors into electric energy. The turbines typically have a high pressure section, an intermediate pressure section and a low pressure section. Steam is first used in the high pressure section. The steam exiting the high pressure section is returned to the boiler, where it enters the reheater tube assembly and is reheated. The reheated steam is returned to the intermediate and then to the low-pressure sections of the turbine. After the steam completes its journey through the turbine sections, it is converted to water in condensers and pumped through feedwater heaters back to the economizer, where it begins the entire steam cycle process again.

7. There are some exceptions to this general configuration among Duke's coal-fired electric generating units. For example, Buck Units 3 and 4 and Cliffside Units 1-4 do not have reheat cycles, while Marshall Units 3 and 4 each have dual reheat cycles; Furthermore, some units, such as Buck Unit 3, do not have an economizer.

8. The thousands of steel tubes and assemblies inside the boilers are called pressurized parts. They are built to withstand extremely high steam pressures and temperatures inside the tubes, as well as hot gases and combustion by products passing outside the tubes.

9. Due to corrosion, erosion, fatigue, pressure, and temperature, the tubes and assemblies must be maintained, repaired, and replaced to maintain the safety and reliability of the units. Otherwise, tubes could fail and boilers could rupture, causing bodily harm to plant workers and disrupting service.

10. Duke regularly undertakes maintenance, repair and replacement activities on its coal-fired electric generating units during planned turbine outages – during which time the unit must be taken offline for thorough inspection of the turbine components. These outages are usually scheduled to occur at each unit every 48 to 84 months, depending upon the needs of the unit and the system, during either the spring or fall. Such outages can last from several weeks to months in duration depending upon the scope of work required.

11. None of the component repairs and replacements cited by Plaintiff in the Notice of Violation or Complaint resulted in an increase in the units' maximum hourly emissions rate or its maximum coal-burning capacity. Rather, the work was intended to and did maintain the availability, reliability, efficiency and safety of the units.

I declare under penalty of perjury that the foregoing is true and correct. Executed this ___ day of January, 2003.

/s/ Rickey J. Deese
Rickey J. Deese

Plant	Unit	Commercial Operation	MNDC
Allen	1	6/11/57	165
	2	11/25/57	150
	3	10/18/59	265
	4	10/10/60	275
	5	7/3/61	270
			1125
Belews Creek	1	8/5/74	1120
	2	12/13/75	1120
			2240
Buck	3	7/1/41	70
	4	9/10/42	38
	5	9/7/53	128
	6	12/3/53	128
			364
Cliffside	1	7/9/40	38
	2	8/11/40	38
	3	5/19/48	61
	4	10/31/48	61
	5	6/20/72	562
			760
Dan River	1	12/11/49	
	2	3/3/50	
	3	8/24/55	142
			142
Lee	1	3/11/51	100
	2	7/16/51	100
	3	12/12/58	170
			370
Marshall	1	3/21/65	385
	2	4/17/66	385
	3	5/15/69	660
	4	5/1/70	630
			2060

Riverbend	4	10/20/52	94
	5	11/22/52	94
	6	8/12/54	133
	7	11/2/54	133
			454

EXHIBIT 59

IN THE UNITED STATES DISTRICT COURT FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA, Plaintiff, ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP Plaintiff-Intervenors, v. DUKE ENERGY CORPORATION Defendant	)	Civil Action No. 1:00 CV 1262

DECLARATION OF KRIS W. KNUDSEN

I, Kris W. Knudsen, being of legal age and pursuant to 28 U.S.C. § 1746, declare:

1. Since 1979 I have been employed by Duke Power Company ("Duke"), the regulated arm of Duke Energy Corporation which has the responsibility for providing electric power to customers in portions of North Carolina and South Carolina. My current position is Senior Air Compliance Technical Consultant. I am submitting this declaration based on my own personal knowledge and belief in support of Duke Energy Corporation's brief in support of its motion for summary judgment.

2. Duke has a generation portfolio that includes 30 coal-fired electric generating units at eight plants located throughout North Carolina and South Carolina. Duke operates these units in compliance with two sets of permits: state operating permits and Acid Rain Program permits. In addition, the Lee Steam Station has a state operating permit issued in accordance with the federal Clean Air Act Title V operating permit program.

3. The state operating permits and Acid Rain Program permits are issued by North Carolina's Department of Environment and Natural Resources ("NCDENR") or by South Carolina's Department of Health and Environmental Control ("SCDHEC"). The Acid Rain Program permits and the Title V permit for Lee Station were subject to notification and review by the EPA.

4. None of these permits restrict the number of hours Duke can operate these units or the amount of electricity the units can generate, rather they require that the units do not exceed the allowable emission limits and that an emissions allowance is surrendered to EPA for each ton of $S0_2$ emitted

5. Duke has continually maintained all of the state operating permits for its units, even for those units which it placed in Extended Cold Shutdown ("ECS"). In the early 1980s, the addition of large nuclear units, combined with lower than expected load growth, led to less use of Duke's smaller coal-fired units, which began spending relatively long periods of time in "reserve shutdown." Accordingly, starting in 1984, Duke placed 15 of its coal-fired units, with aggregate name plate capacity of about 1440 megawatts, into ECS. Duke made definitive plans for preserving and

conditioning these units while in ECS so that they could be returned to service when demand dictated.

6. During ECS, Duke developed an enhanced maintenance program, which it called the "Plant Modernization Program" or PMP, Performing maintenance, repair and replacement projects on the units while in ECS allowed Duke to utilize its in-house engineering, project management and maintenance resources in an optimum fashion so as to distribute those resources over the units in ECS as well as the other units in the Duke system.

7. On behalf of Duke, Keith Sipe and I regularly communicated with NCDENR on a frequent basis to keep Duke's permits current for those units in ECS and PMP, for permit renewal, or to adjust the annual stack testing schedule required by the permits to accommodate the ECS and PMP schedule. Keith Sipe and I also met with EPA in 1991 to discuss the status of our PMP units relative to allocation of S02 allowances under the Acid Rain Program.

8. EPA's Acid Rain Program was implemented under the Clean Air Act Amendments of 1990. In addition to regulating SO_2 emissions from utility units, the Acid Rain Program also requires existing utility boilers to meet certain NOx emissions limitations. To comply with these requirements, starting in about 1994 and continuing throughout the 1990s, Duke has installed NOx controls called "low-NOx burners" on its existing coal-fired units, thereby lowering their NOx emissions rates to 0.5-0.68.lbs/mmBtu for the two Belews Creek units and less than 0.45 lbs/mmBtu for all other units.

9. Duke is also subject to the so-called NOx SIP Call, under which several states in the eastern half of the United States were required to amend their State Implementation

Plans (SIPS) for NOx to establish a cap-and-trade NOx control system. The NOx SIP Call essentially requires utilities in these states to control, during the "ozone season" (i.e., May-September), the total NOx emissions from their existing and new boilers alike to achieve an overall average level of control of 0.15 lbs/mmBtu. To comply with the NOx SIP Call by 2004, Duke is currently installing additional NOx controls at many of its units. Duke has established NOx emissions allowance accounts and has applied for NOx SIP Call permits for each of its coal-fired units.

10. In addition to these restrictions, North Carolina in 2002 enacted a stringent new air emissions control law which requires greater control of utility SO_2 and NOx emissions than do the current federal requirements. North Carolina's law establishes a system emissions cap for the major utility systems in the state. Rather than mandating unit-by-unit controls, it thus allows Duke to install controls where it makes most technical and economic sense to reduce overall emissions (similar to a cap-and-trade program).

11. Duke's program to meet the new state law will involve the installation of additional NOx controls on 24 units and SO_2 controls on 12 units (covering more than 70% of Duke's coal-fired generation), at a cost of approximately $1.5 billion.

I declare under penalty of perjury that the foregoing is true and correct. Executed this 30th day of January, 2003.

/s/ Kris W. Knudson
Kris W. Knduson

EXHIBIT 66

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	:	
Plaintiff,	:	
ENVIRONMENTAL DEFENSE, NORTH CAROLINA SIERRA CLUB, NORTH CAROLINA PUBLIC INTEREST RESEARCH GROUP	:	Civil Action No. 1:00 CV 1262
Plaintiff-Intervenors	:	
v.	:	
DUKE ENERGY CORPORATION,	:	
Defendant.	:	

Washington, D.C.

Monday, November 25, 2002

Videotaped deposition of RANAJIT SAHU, a witness herein, called for examination by counsel for Defendant Duke Energy Corporation in the above-entitled matter, pursuant to notice, the witness being duly sworn by MARY GRACE CASTLEBERRY, a Notary Public in and for the District of Columbia, taken at the offices of U.S. Department of Justice, 1425 New York Avenue, N.W., Washington, D.C. at 9:22 a.m., Monday, November 25, 2002, and

the proceedings being taken down by Stenotype by MARY GRACE CASTLEBERRY., RPR, and

* * *

[7] RANAJIT SAHU,

was called as a witness by counsel for Defendant Duke Energy Corporation, and having been duly sworn by the Notary Public, was examined and testified as follows:

EXAMINATION BY COUNSEL FOR DEFENDANT DUKE ENERGY CORPORATION

BY MR. JABER:

Q. Good morning, Mr. Sahu.

A. Good morning.

Q. Would you state your name for the record, please?

A. my name is Ranajit Sahu. I can spell it for you if you want.

Q. Go ahead and do that, please.

A. First name is spelled R-a-n-a-j-i-t. The last name is S-a-h-u.

Q. And you also, go by "Ron Sahu," is that right?

A. I also go by "Ron."

(Sahu Exhibit No. 1 was marked for identification.)

BY MR. JABER:

Q. You were just handed Exhibit Sahu 1. Will you identify the exhibit, please?

A. It looks like it's a notice of deposition

* * *

[142] Q. I asked you, in the WEPCO situation, after the WEPCO – the WEPCO court said you cannot apply actual to potential to this facility because the units have begun normal operations. Do you agree with that? You agree this is what the court said?

A. Yes.

Q. And I'm asking you, once I realize that the rules cannot be applied that way, let's say I agree with that, let's say EPA agrees with that, the rules cannot be applied that way, what in the 1980 rules tells me how I should determine whether those physical changes resulted in a net emissions increase, and were therefore a major modification under the PSD rules?

A. I answered that before. I mean, I told you my answer just a few minutes ago to that.

Q. Is your answer is, there is nothing in the 1980 rules that defines the test?

A. Correct.

Q. Thank you.

(Sahu Exhibit No. 13 was marked for identification.)

BY MR. JABER:

Q. Can you identify Exhibit Sahu 13, Mr. Sahu?

* * *

[156] projected actual.

Q. Okay. Can you show me where in the 1980 rules these tests, the other tests that you did for the 1980 – sorry. Let me start again.

Can you show me where in the 1980 rules the other tests that you applied to the Duke units that were subject to the 1980 rules, where those tests are set forth in the 1980 rules?

A. They're not set forth in the 1980 rules.

Q. Where are they? Where did you get them from?

A. The WEPCO regulations talk about using actual to future actual or representative annual actual.

Q. So you applied the actual to future projected actual methodology in the WEPCO rule to these units too?

A. Yes, I did.

MR. JABER: Let's go off the record.

THE VIDEOGRAPHER: Off the record. 2:29, 52 seconds.

(Recess.)

THE VIDEOGRAPHER: On the record, 2:45, 58 seconds.

BY MR. JABER:

* * *

EXHIBIT 72

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA, Plaintiff, vs DUKE ENERGY CORPORATION, Defendant.	Civil Action No. 1:00 CV 1262 Washington, D.C. October 4, 2001 Volume I

Deposition of:

DAVID A. LLOYD

called for examination by counsel for the defendant, pursuant to notice, at the offices of Hunton & Williams, 1900 K Street, Northwest, Washington, D.C., commencing at 9:30 a.m., before James M. Turner, RMR, Notary Public for the District of Columbia.

* * *

[4] P-R-O-C-E-E-D-I-N-G-S

Thereupon,

DAVID A. LLOYD

was called as a witness and, after being duly sworn by the notary, was examined and testified as follows:

MR. COTTINGHAM: The court reporter signed the confidentiality agreement.

MR. KAPLAN: Okay, good.

MR. COTTINGHAM: I took care of that issue before you all got here.

EXAMINATION BY COUNSEL FOR THE DEFENDANT

BY MR. COTTINGHAM:

Q Your name is David A. Lloyd?

A Yes.

Q You work for the Environmental Protection Agency?

A Yes.

Q You are here in this case pursuant to a 30(b)(5) and (6) deposition notice. Is that correct?

A That's correct.

* * *

[295] Q Is there any particular part of the regulations that caused you to use the GADS data?

A The regulation didn't specify what specific data to use. And I don't think it was really contemplated or laid out in the regulation specific data, just methodologies.

Q Did you use the pre-1992 regulations at all in preparing your calculations?

A For the actual to potential tests that we did, yes.

Q For those calculations you used the pre-1992 regulations?

A We applied the actual potential to the potential test based on those pre-'92 regulations.

Q Did you use the pre-1992 regulations in any other way?

A To the extent they define actual emissions before the project, that in combination with the WEPCO [296] rule, yes.

MR. KAPLAN: Counsel, when you reach a convenient stopping point we could use a break.

MR. COTTINGHAM: We can do that right now while I'm marking this.

(At 11:37 a.m., a recess was taken.)

(No. 15 – Rules in effect before 1992, marked for identification.)

BY MR. COTTINGHAM:

Q Let me show you exhibit 15, which are the rules in effect before 1992. And the reason I wanted to show you those, you said that these helped you to define actual emissions under the 1992 rules, and I wanted you to show us first how you do that or where that is.

A I'm looking under the definition of actual emissions.

Q What page is the page number at the bottom?

A Twenty-four.

Q Okay.

A Where it defines the baseline emissions. Then under number ii, Roman numeral ii, to be the ton – let's see – to be the tons per year emissions which the unit actually emits the pollutant during a two-year [297] period

which preceded a particular date. Then if you go down to number iv, it talks about the emissions after the project being the potential to emit.

Q Number iv says, "For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date." Is that what you are talking, about?

A Uh-huh (affirmative response).

Q Is that the basis for the actual to potential methodology?

A Yes.

Q Now, is it the agency's position that the actual to potential methodology is the methodology that should be used for work performed before 1992?

A It's our position that the actual to potential test is the methodology that the regulation requires before '92.

Q Now, does the WEPCO case tell you anything about whether that is a valid position?

MR. KAPLAN: Objection.

THE WITNESS: The WEPCO case provided for an additional calculation for electric utilities.

* * *

EXHIBIT 89

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

May 10, 1989

MEMORANDUM

SUBJECT: Utility Boiler Life Extension/Repowering (ESD Project 88/95)

FROM: Jack R. Farmer, Director [/s/ Jack]
Emission Standards Division (MD-13)

TO: See Below

The purpose of this memorandum is to request your input and assistance on a project we have started to evaluate life extension and repowering of utility boilers.

Earlier this year, we initiated a study to determine the extent of activities by the electric power companies in utility boiler life extension and repowering. We are undertaking this project along with the Office of Policy, Planning and Evaluation (OPPE), the Office of Policy Analysis and Review (OPAR), and the Stationary Source Compliance Division (SSCD) of the Office of Air Quality Planning and Standards (OAQPS). The study is being done so that we may obtain information to distinguish the types of activities that constitute boiler life extension and repowering from those that are routine maintenance. By gathering this information, we will be in a better position to provide assistance regarding determinations of modification and/or reconstruction and to evaluate any necessary regulatory changes. We are seeking the information presented in Attachment 1 (life extension) and Attachment 2 (repowering). We are planning

to request the information from those utilities that we have identified as having at least considered boiler life extension or repowering, as listed in Attachments 3 and 4, respectively.

Recently we learned that, as a result of an inquiry from Congressman Dingell, Regions IV and VI are seeking the same types of information as we are from two specific utilities believed to have undertaken boiler life extension actions. We have also learned that Region IV intends to solicit this information from all of the utilities within their Region. I understand that Region IV's objective is to determine if any facilities have improperly avoided either prevention of significant deterioration (PSD) permits or applicability of new source performance standards (NSPS).

To avoid duplicate information requests and to facilitate the most effective and complete data gathering effort for life extension and repowering, I would like to solicit input from each Region on the following topics:

1. Are there other utilities (beyond those identified in Attachments 3 and 4) in each Region known or believed to have considered (or undertaken) boiler life extension or repowering activities? Our information is derived from journal articles and limited contact with both EPA and industry personnel and is probably not complete.

2. Are any Regions soliciting information of the type found in Attachments 1 and 2 from utilities known or believed to have considered (or undertaken) boiler life extension or repowering activities, and would you consider using these attachments as a part of your information gathering?

3. Would you consider a Regional Information gathering effort from each utility identified in Item 1 above, and in Attachments 3 and 4, using Attachments 1 or 2 as a part of the mailing? Further, would you consider a Regional data gathering program that would include all utilities?

Please provide me your responses by May 26, 1989. If you have any questions, contact Bill Maxwell (FTS 629-5430).

4. Attachments

Addresses:

Irwin L. Dickstein, Director, Air and Toxics Division, Region VIII
Louis F. Gitto, Director, Air Management Division, Region I
William B. Hathaway, Director, Air, Pesticides, and Toxics Division, Region VI
David P. Howekamp, Director, Air Management Division, Region IX
David Kee, Director Air and Radiation Division, Region V
Thomas J. Maslany, Director, Air Management Division, Region III
Gary L. O'Neal, Director, Air and Toxics Division, Region X
Conrad Simon, Director, Air and Waste Management Division, Region II
Winston A. Smith, Director, Air, Pesticides, and Toxic Management Division, Region IV
William A. Spratlin, Director, Air and Toxic Management Division, Region VII

cc: Ron Shafer, SSCD (EM0341)
Mike Shelby, OPPE (PM-221)
Tony Wayne, OPAR (ANR-443)

Attachment 3. List of Potential Utility Boiler Life Extension Projects

Region		State	Utility	Site
1	I	Connecticut	Northeast Utilities	South Meadow Station
1	I	Massachusetts	Boston Edison	New Boston
1	I	Massachusetts	Boston Edison	Mystic
2	II	New Jersey	GPOSC/Jersey Central Power and Light	
2	II	New Jersey	Atlantic City Electric	B.L. England
2	II	New Jersey	Atlantic City Electric	Deepwater
2	II	New York	New York State Electric and Gas	Greenidge
2	II	New York	Consolidated Edison	Ravenswood
2	II	New York	Niagra Mohawk	C.P. Huntley
2	II	New York	Central Hudson Gas and Electric	Danskarmor Point
3	III		[Illegible] Power	
3	III	Maryland	Potomac Electric Power (PEPCO)	Dickerson
3	III	Pennsylvania	GPUSC/Metropolitan Edison	Titus
3	III	Pennsylvania	GPUSC/Pennsylvania Electric Company	
3	III	Pennsylvania	Philadelphia Electric	Eddystone -
3	III	Pennsylvania	Pennsylvania Power and Light	Brunner Island
3	III	Virginia	Virginia Electric Power (VEPCO)	Chesterfield
3	III	Virginia	Virginia Electric Power (VEPCO)	Yorktown

3	III	Virginia	Potomac Electric Power PEPCO	Potomac River
3	III	West Virginia	Virginia Electric Power (VEPCO)	Mt. Storm
4	IV		Tennessee Valley Authority	
4	IV	Florida	Florida Power Corporation.	Suvanee River
4	IV	Florida	Tampa Electric	Francis J. Cannon
4	IV	North Carolina	Duke Power Company	Allen
4	IV	North Carolina	Duke Power Company	Riverbend
4	IV	North Carolina	Duke Power Company	[Illegible] River
4	IV	North Carolina	Duke Power Company	Lee
4	IV	North Carolina	Duke Power Company	Buck
4	IV	North Carolina	Duke Power Company	Cliffside
5	V	Illinois	Commonwealth Edison	
5	V	Indiana	Northern Indiana Public Utility	
5	V	Indiana	Public Service Company of Indiana	R.E. Gallagher
5	V	Indiana	Public Service Company of Indiana	Wabash River
5	V	Michigan	Consumers Power Corporation	J.P. Whiting
5	V	Michigan	Consumers Power Corporation	D.E. Karen
5	V	Michigan	Consumers Power Corporation	J.E. Campbell

5	V	Michigan	Consumers Power Corporation	B.C. Cobb
5	V	Michigan	Consumers Power Corporation	J.C. Weadock
5	V	Michigan	Detroit Edison	
5	V	Minnesota	Northern States Power	Riverside
5	V	Minnesota	Minnesota Power	M.L. Hibard
5	V	Ohio	Cincinnati Gas and Electric	[Illegible] Beckjord
5	V	Ohio	Cleveland Electric Illuminating Company	
5	V	Wisconsin	Wisconsin Power and Light	
5	V	Wisconsin	Wisconsin Electric Power	Port Washington
5	V	Wisconsin	Wisconsin Public Service	
5	V	Wisconsin	Wisconsin Electric Power	Oak Creek
6	VI	New Mexico	Southwestern Public Services	
6	VI	Texas	Texas Utilities Generating Company (ALCOA)	Sandov
7	VII	Iowa	Iowa Public Services	
7	VII	Kansas	Kansas City Power and Light	
7	VII	Missouri	Independence Power and Light	Blue Valley Station
7	VII	Nebraska	Omaha Public Power	
8	VIII	Colorado	Public Service of Colorado	

9	IX	Arizona	Arizona Public Utilities	
9	IX	California	San Diego Gas and Electric	
9	IX	California	Pacific Gas and Electric Company	Pittsburg
9	IX	Hawaii	Hawaii Power	Kabe
Unknown			Centeris Power	
Unknown			Southern Company Services	

EXHIBIT 99

DUKE POWER COMPANY
LEGAL DEPARTMENT
P.O. BOX 33189
CHARLOTTE, N.C. 26242

August 17, 1983

RONALD V. SHEARIN
ASSISTANT GENERAL COUNSEL **(704) 373-7207**

Mr. Robert F. Helms, Director
Division of Environmental Management
North Carolina Department of Natural
Resources and Community Development
Post Office Box 27687
Raleigh, North Carolina 27611-7687

Re: *Air Permit Requirements*

Dear Mr. Helms:

We are writing to request your concurrence with our interpretation of State regulatory requirements which might be applicable to Duke Power's placement of designated coal-fired units in an extended cold shutdown status. In particular, we are concerned about the future application of Regulations 15 NCAC 2D. 0524 (NEW SOURCE PERFORMANCE STANDARDS) and 15 NCAC 2D. 0530 (PREVENTION OF SIGNIFICANT DETERIORATION).

With recent load growth being less than previously anticipated and with nuclear units coming on-line at both McGuire and Catawba Nuclear Stations, it has become apparent that the Company will not need for several years some of our older coal-fired units in order to have sufficient reserves for meeting projected demand during the 1980's and early 1990's. Beginning in 1984 and during

subsequent years, the Company plans to place a series of older units in an extended cold shutdown status. Based on information currently available, it appears that these units will not be needed until approximately 1991, when they will be brought back on-line with minimal expenditures. While in an extended cold shutdown mode, the units will be properly maintained to permit bringing them on-line as quickly as possible when needed. As a part of the maintenance program, dehumidified air will be circulated through the units to prevent corrosion. It is anticipated that a period of four to six weeks will be required to return a unit to service when needed.

During the period of temporary cold shutdown of these units, it is our intention to retain all operating permits issued by the State under the North Carolina Administrative code. Monitoring and reporting will continue for all stations under the NPDES program while we request exemption from permit conditions applicable to the operation of air pollution control equipment for those units not in operation. Upon restart, Duke will comply with all air permit conditions.

The question has been raised as to whether the Company would be required to meet standards of performance for new stationary sources (NSPS) or be subject to regulations for prevention of significant deterioration of air quality (PSD) at the time of reactivation of units which would have been in an extended shutdown status as described above.

We understand that NSPS regulations would not apply to such reactivation since all of the units in question were constructed well in advance of the August 17, 1971 date set forth in 40 CFR 60.40 and since the reactivation would

not constitute a "modification" under 40 CFR 60.2 or a "reconstruction" under 40 CFR 60.15.

It is also our understanding that such reactivation of a unit subsequent to an extended cold shutdown would not trigger the preconstruction review and permitting requirements of PSD regulations. There would not be a "major modification" of a unit as defined in 40 CFR 51.24(b)(2) inasmuch as there would be no change in the method of operation of the unit in question and air emissions would be no greater than when the unit was previously in operation. We further understand that the State would continue to retain emissions from the temporarily shutdown units in the State air emissions inventory for planning purposes.

We would appreciate your concurrence with our interpretation of the regulations in question prior to our implementation of the extended cold shutdown program for designated units on the Duke system. Please let us know if you need further information or if you desire a meeting in person to discuss this matter further.

Sincerely yours,

DUKE POWER COMPANY

/s/ Ronald V. Shearin
Ronald V. Shearin

cc: Mr. James Wilburn

Chief, Air Management Branch

U.S. Environmental Protection Agency Region IV

345 Courtland Street, N.E.
Atlanta, Georgia 30308

bcc: B.E. Davis
S.C. Griffith
J.E. Lansche
W.O. Parker
B.K. Sipe

EXHIBIT 100

DUKE POWER COMPANY
LEGAL DEPARTMENT
P. O. Box 33189
CHARLOTTE, N. C. 28242

RONALD V. SHEARIN
ASSISTANT GENERAL COUNSEL (704) 373-7207

August 17, 1983

Mr. Roger E. Davis, P.E.
Assistant Deputy Commissioner
Environmental Quality Control
South Carolina Department of Health
and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

Re: Air Permit Requirements

Dear Mr. Davis:

We are writing to request your concurrence with our interpretation of State regulatory requirements which might be applicable to Duke Power's placement of designated coal-fired units in an extended cold shutdown status. In particular, we are concerned about the future application of Regulations 61-62.1 and 61-62.5.

With recent load growth being less than previously anticipated and with nuclear units coming on-line at both McGuire and Catawba Nuclear Stations, it has become apparent that the Company will not need for several years some of our older coal-fired units in order to have sufficient reserves for meeting projected demand during the 1980's and early 1990's. Beginning in 1984 and during subsequent years, the Company plans to place a series of

older units in an extended cold shutdown status. Based on information currently available, it appears that these units will not be needed until approximately 1991, when they will be brought back on-line with minimal expenditures. While in an extended cold shutdown mode, the units will be properly maintained to permit bringing them on-line as quickly as possible when needed. As a part of the maintenance program, dehumidified air will be circulated through the units to prevent corrosion. It is anticipated that a period of four to six weeks will be required to return a unit to service when needed.

During the period of temporary cold shutdown of these units, it is our intention to retain all operating permits issued by the State. Monitoring and reporting will continue for all Stations under the NPDES program while we request exemption from permit conditions applicable to the operation of air pollution control equipment for those units not in operation. Upon restart, Duke will comply with all air permit conditions.

The question has been raised as to whether the Company would be required to meet standards of performance for new stationary sources (NSPS) or be subject to regulations for prevention of significant deterioration of air quality (PSD) at the time of reactivation of units which would have been in an extended shutdown status as described above.

We understand that NSPS regulations would not apply to such reactivation since all of the units in question were constructed well in advance of the August 17, 1971 date set forth in 40 CFR 60.40 and since the reactivation would not constitute a "modification" under 40 CFR 60.2 or a "reconstruction" under 40 CFR 60.15.

It is also our understanding that such reactivation of a unit subsequent to an extended cold shutdown would not trigger the preconstruction review and permitting requirements of PSD regulations. There would not be a "major modification" of a unit as defined in 40 CFR 51.24(b)(2) inasmuch as there would be no change in the method of operation of the unit in question and air emissions would be no greater than when the unit was previously in operation. We further understand that the State would continue to retain emissions from the temporarily shutdown units in the State air emissions inventory for planning purposes.

We would appreciate your concurrence with our interpretation of the regulations in question prior to our implementation of the extended cold shutdown program for designated units on the Duke system. Please let us know if you need further information or if you desire a meeting in person to discuss this matter further.

Sincerely yours,

DUKE POWER COMPANY

/s/ Ronald V. Shearin
Ronald V. Shearin

cc: Mr. James Wilburn
Chief, Air Management Branch
U.S. Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

bcc: B. E. Davis
S. C. Griffith
J. E. Lansche
W. O. Parker
B. K. Sipe

EXHIBIT 101

South Carolina Department of Health and Environmental Control

[LOGO]

[Names And Addresses Omitted In Printing]

August 23, 1983

Mr. Ronald V. Shearin
Assistant General Counsel
Duke Power Company
Legal Department
P. O. Box 33189
Charlotte, NC 28242

xc : B. E. Davis
B. K. Sipe
W. O. Parker
08/26/83

Dear Mr. Shearin:

We concur with your interpretation of the air pollution regulations in regard to the extended cold shutdown of your fossil-fuel fired steam generating units. As long as the shutdown is temporary the units would not be subject to the PSD or NSPS regulations upon reactivation of the units. The conditions you suggested such as equipment maintenance, retention of operating permits and the State's retention of the emissions in the State Emission Inventory will qualify the shutdown as temporary according to our interpretation of the regulations and according to written determinations we have received from EPA.

As you requested, permit conditions relating to satisfactory operational experience, source testing, and reporting requirements will be waived during shutdown. However, within 90 days of re-starting the units a source test will be required to determine compliance with the particulate matter standard.

If you have any further questions regarding air regulations, please contact Gary Nelson at (803) 758-5406.

Very truly yours,

/s/ William W. Culler
William W. Culler, P.E., Director
Division of Engineering Services
Bureau of Air Quality Control

WWC:RKC:is

EXHIBIT 102

[LOGO] North Carolina Department of Natural
Resources & Community Development
James B. Hunt, Jr., Governor Joseph W. Grimsley, Secretary

DIVISION OF ENVIRONMENTAL MANAGEMENT

September 15, 1983

Mr. Ronald V. Shearin
Assistant General Counsel
Duke Power Company
Legal Department
Post Office Box 33189
Charlotte, North Carolina 28242

xc : B. E. Davis
B. K. Sipe
W. O. Parker
09-30-83

Dear Mr. Shearin:

This is in response to your questions about air permit requirements for coal-fired units in an extended cold shutdown status. We concur with your interpretations of the existing permit requirements. Placing units constructed prior to August 17, 1971, in an extended cold shutdown status does not affect the exempt status from 15 NCAC 2D .0524 New Source Performance Standards. If no change in the method of operation will occur and air emissions will not increase then the "Modification" provisions of 40 CFR 60.2 do not apply. The reconstruction provisions of 40 CFR 60.15 will apply if roughly 50% of the cost of a new unit is spent on the existing unit.

The units do not have to meet the Prevention of Significant Deterioration (PSD) requirements of 15 NCAC 2D .0530 if the existing permits remain active and the units are not used for any emissions credits or to project compliance with ambient standards.

The Clean Air Act changes resulting from Federal Legislative action between now and 1991 may affect the interpretations of today. The changes may include the following:

1. Acid rain legislation requirements
2. State-of-the-art changes for boilers and control technology
3. Ambient standard changes
4. Continuous emission or fuel monitoring requirements
5. G.E.P. stack height

The planned shutdown and emergency use of units will be addressed in the Environmental Management Commission review of the utility particulate regulation.

Your planned extended cold shutdowns indicate that Duke Power Company has good management for the future of electric utility needs. We endorse your use of the most efficient units. This will result in less particulate emissions in the State.

Sincerely yours,

/s/
for Robert F. Helms
Director

cc: Fin Johnson
Jim Wilburn

EXHIBIT 103

FOSSIL PRODUCTION DEPARTMENT
P.O. BOX 33189, 422 SOUTH CHURCH STREET
CHARLOTTE, N.C. 28242
(704) 373-4011

April 19, 1985

Mr. Roy M. Davis, Regional Supervisor
Division of Environmental Management
P.O. Box 370
Asheville, North Carolina 28802

Subject: Malfunction Determination
Cliffside Steam Station
File: CS-700.20

In response to your letter dated March 18, 1985 concerning the above subject matter, we have provided a summary of actions that will be taken to minimize opacity and precipitator trips. These actions are given as follows:

Opacity reduction – A number of procedures, components, and systems have been implemented or is currently being supplied to reduce emissions from the Cliffside Station. Units 1 through 4 have been placed in extended cold shutdown. These units will be out of service for several years. New controls and components will be installed in these units which will provide for a more efficient operation, hence a reduction in pollutant emissions.

New, updated boiler controls and have been installed on Unit 5. These controls have made it possible to reduce minimum load from the previous 250 MW to approximately 100 MW. The lower load operation will allow fewer startups, and the associated emissions during startup/shutdown will be reduced.

Updated controls and a flue gas conditioning system are scheduled for installation on the Unit 5 precipitator by December, 1985. The new controls and gas conditioning system should aid in a significant reduction in opacity.

Section Trips – To-date, we have had only three precipitator section trips on the Unit 5 precipitator this year. In 1984 we had a total of eight section trips. We do not consider this to be an excessive number of section trips when compared to other precipitators. However, when sufficient outage time permits (allowing 2-3 days for the precipitator to cool before entering and 2 days for cleaning), an internal inspection of the precipitator will be conducted. The wires and plates will be manually cleaned, as necessary and any broken or damaged wires will be replaced. This should enhance the reliability of the unit and minimize section trips.

Miscellaneous – During startup and shutdown, numerous pumps, piping loops, electrical equipment, etc. are brought into service or taken out of service. Many of these systems are totally automated and some are manually controlled. Synchronizing these systems during non-steady state conditions is quite a demanding process and at times errors do occur. Duke Power has extensive ongoing programs and classes to maximize worker efficiency. These programs have been quite effective in minimizing human error in the work place. The Cliffside plant, as well as other Duke Power stations, have a continual program of increasing plant efficiency and minimizing pollutant emissions.

If additional discussion is required, please contact Quinc Corey at (704) 373-7245 or myself at (704) 373-4436.

Very truly yours,

/s/ Keith Sipe
B. Keith Sipe
System Environmentalist
Fossil-Environmental
Compliance

QDC/gw

cc: Ogden Gerald, Asst. Chief
NC-DEM Air Quality, Raleigh

EXHIBIT 107

NORTH CAROLINA DIVISION
OF ENVIRONMENTAL MANAGEMENT

Air Quality Action Request

Computer ___

Name	Location	Reg/Co. /Prem. No.
Duke Power Co., Buck Steam Station	E. Spencer, Kowan County	03/80/00004

Contact Telephone

Type Action: CI ___ EE ___ SR ___ PC ___ VE ___ PI ___
Other Permit Renewal

Air Program Status 03 ___ ___ ___ ___
Class AIA Chg _____

Action Requested By:	Address/Phone	Rec'd Date
Mr. E. Keith Sipe, System Environmentalist	(704) 373-4011	3/13/87

Last Insp. Date _____ Action Date 6/3/87

Next Insp. Date _____

Permit # 378685, 378585 Issued 6/8/87 Expires 3/31/92
378485, 378385 Stip. # _____ Met Y/N _____

Recommendations:	Signature	Date
MRO will issue Permit Nos. 3786R5, 3785R3784R3, & 3783R5	Yin-Pong Chang /s/ Yin Pong Chang	6/8/87

Dist: Yellow (Central File) – Blue (Region) – White (Opt.)
Specify /s/ _____

1. Application is for renewal of Permit Nos. 3786R6, 3785R4, 3784R4, and 3783R4 to operate the following coal fired boilers at Buck Steam Station:

Permit No.	ESP Unit No.	Boiler No.	Max. Heat Input (MBTU/hr.)	KSP Surface Area (Sq. Ft.)
3786R4	3	5 & 6	2 x 672	2 x 80,640
3785R4	4	7	672	80,640
3784R4	5	8	1440	152,280
3783R4	6	9	1440	152,280

2. On January 20, 1987, the writer inspected the facility. None of the units were in operation during the inspection. Unit Nos. 3, 4, & 5 are currently in the Plant Modernization Program (PMP) and are not expected to be in operation until 1989. Unit No. 6 will only be operated on a reserve basis. The facility is considered to be in compliance with the applicable regulations.

3. PSD, NSR, NSPS and NESHAP do not apply.

4. Issue Permit Nos. 3786R5, 3785R5, 3784R5, and 3783R5.

/pb

EXHIBIT 13

BEFORE THE SOUTH CAROLINA
PUBLIC SERVICE COMMISSION
COLUMBIA; SOUTH CAROLINA

HEARING #8323 JULY 30, 1985 11:00 A.M.

DOCKET NO. 85-78-E: APPLICATION BY DUKE POWER COMPANY FOR AUTHORITY TO ADJUST AND INCREASE ITS ELECTRIC RATES AND CHARGES.

HEARING BEFORE: THE HONORABLE FRANKLIN E. ROBSON, ADMINISTRATIVE LAW JUDGE, PRESIDING; AND CHAIRMAN FRED A. FULLER, JR., VICE-CHAIRMAN CECIL A. BOWERS, AND COMMISSIONERS HENRY G. YONCE, MARJORIE AMOS FRAZIER, RUDOLPH MITCHELL, CAROLINE H. MAASS, AND GUY BUTLER.

TRANSCRIPT OF TESTIMONY AND PROCEEDINGS
VOLUME 1

* * *

[61] TESTIMONY OF

WILLIAM S. LEE

FOR

DUKE POWER COMPANY

SCPSC DOCKET NO. 85-78-E

Q. PLEASE STATE YOUR NAME, ADDRESS AND YOUR POSITION WITH DUKE POWER COMPANY.

A. My name is William S. Lee. My business address is 422 South Church Street, Charlotte, North Carolina 28242. I am Chairman of the Board and Chief Executive

IN THE UNITED STATES DISTRICT COURT
FOR THE MIDDLE DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA,	)	
Plaintiff,	)	
v.	)	CIVIL NO. 1:00CV1262
DUKE ENERGY CORPORATION,	)	
Defendant.	)	

EXHIBITS IN SUPPORT OF UNITED STATES' MOTION FOR PARTIAL SUMMARY JUDGMENT

(Filed Jan. 31, 2003)

* * *

Officer of Duke Power Company, and a registered professional engineer in North Carolina and South Carolina.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the rate increase that the Company is seeking. We are requesting an increase of 19.87%, or approximately $143 million, based on the test year which is the twelve (12) months ended June 30, 1984. Of this requested rate increase, approximately 84% relates to the cost impact of Catawba Unit 1 coming into commercial operation. These Catawba costs, as well as other increased costs, must be recovered to provide for a fair and reasonable return.

Q. MR. LEE, PLEASE DESCRIBE THE CATAWBA STATION AND TELL US WHEN CATAWBA UNIT 1 WILL GO IN COMMERCIAL OPERATION?

A. The Catawba Station is a two unit nuclear generating station with a capacity of 1145 MW for each unit. The Station is located on the shores of Lake Wylie in South Carolina near Rock Hill. The reactor systems of the Catawba Station are almost identical to the McGuire Nuclear Station, which consists of two units with a

* * *

[65] the most recent order on March 1, 1984, or in any other order which would cause the Company to do anything except complete the construction of Catawba on a timely basis.

Q. MR. LEE, WHAT IMPACT WILL COMMERCIAL OPERATION OF CATAWBA UNIT 1 HAVE ON THE COMPANY'S GENERATING RESERVES?

A. The Company's generating capability, including firm purchases, is 13,782 MW. As this testimony is being written, our forecasted territorial peak for the summer of 1985 is 12,150 MW based on normal weather. This translates into a generating reserve margin of 13.4% before consideration of reserve capability that Catawba Unit 1 will provide. Catawba Unit 1 will add 1,145 MW to our system capability which will raise the reserve margin to 22.9% on paper at the forecasted summer 1985 peak demand.

The Company has an on-going outage requirement for refueling its nuclear units. Further, one of our major fossil units (Belews Creek Unit 1) will be out of service for repairs during the summer of 1985. Considering only the outage at Belews Creek Unit 1 and no other scheduled or unscheduled outages, which experience tells us will occur, our generating reserve margin for the summer peak is forecasted to be only 13.6% after including Catawba Unit 1. Catawba Unit 1 is therefore essential for system reliability in meeting the 1985 summer load.

Q. WHAT WILL BE THE OVERALL EFFECT ON DUKE POWER COMPANY'S SYSTEM RELIABILITY WHEN THE CATAWBA STATION COMES ON LINE?

A. Obviously, when any new generating capacity comes on line, the system reliability will improve. We believe our system reliability will be significantly enhanced for several reasons.

[66] Our oldest coal-fired units still in service and the year of initial service are as follows:

Lee Unit 1	1951
Riverbend Unit 4	1952

Buck Unit 6	1953
Dan River Unit 3	1955

Marshall, which is one of the most efficient coal-fired steam stations in the country, began operation in 1965 and is now twenty years old. Cliffside 5 has been in service for thirteen years, and our newest coal-fired station, Belews Creek, is eleven years old.

In addition, the Company has removed several small coal-fired units from the stated system net capability due to their advanced age (27 to 43 years old) and condition. These units are being placed in a state of extended cold shutdown pending studies of their usefulness for future needs if they should be rehabilitated.

By 1995, 57% of the Company's present fossil steam generating capacity will be 25 or more years old. Due to the relatively geriatric condition of our fossil steam generating units, we believe the addition of the Catawba units will significantly enhance system reliability. We are also encouraged by the performance of our Oconee Nuclear Station, as well as our McGuire Nuclear Station. Nuclear generation carried 56% of the Company's total system load during the calendar year 1984.

We believe that Catawba Unit 1 will perform quite well considering it is a brand new nuclear unit. Our figures in this case include the assumption that Unit 1 will operate at a 60% [67] capacity factor, which was the average for the nation's nuclear units in 1983.

Q. MR. LEE, WHAT IS DUKE'S PROPORTIONATE INTEREST IN THE CATAWBA STATION INCLUDED IN RATE BASE IN THIS CASE?

A. While Duke has title to 25% of Unit 1, the provisions of the interconnection agreements with the joint owners result in the Company's interest being allocated evenly between Units 1 and 2. This results in the Company having a 12.5% operating investment in both Unit 1 and Unit 2. The South Carolina retail portion of Duke's investment in Unit 1, which the Company is including in rate base in this case, is $67.8 million, including nuclear fuel.

Q. WHAT IMPACT DOES CATAWBA UNIT 1 HAVE ON THE REQUESTED RATE INCREASE?

A. There will be operating costs incurred and return required on the company's investment in Unit 1. The Company is also contractually obligated to begin purchasing capacity and energy from the joint owners of the Catawba Station when Unit 1 operates for one hundred (100) hours at full power.

Q. MR. LEE, WHY WILL THE COMPANY INCUR COSTS FOR PURCHASED POWER FROM THE CATAWBA STATION?

A. The Company entered into a series of contracts (the Catawba Agreements) whereby it sold 87.5% of the Catawba Station to its Wholesale customers. Under the Catawba Agreements, we are contractually obligated to purchase capacity and energy from the joint owners over a period of years. This buy-back provision was an essential element necessary to consummate the sale. This feature of the transaction was necessary to make the purchase of Catawba economically feasible for the wholesale customers.

* * *

[89] the sale to PMPA was an absolute financial necessity. Therefore, we proceeded to renegotiate the contract with PMPA.

Q. YOU TESTIFIED PREVIOUSLY CONCERNING THE SAVINGS ARISING FROM CATAWBA, ARE THERE ANY OTHER EFFICIENCIES THE COMPANY HAS ACHIEVED TO HELP IT HOLD DOWN RATE INCREASES?

A. Yes. Each of the six nuclear units Duke has completed have been completed at the lowest cost per kw of any unit completed during that time frame. Duke also has the lowest cost fossil capacity in the country. These benefits are a direct result of Duke's unique ability to design and construct its generating facilities in-house. Duke is the only investor-owned utility in the country which has such a capability.

Not only are our generating units built at the lowest possible cost, our nuclear and coal units also consistently have been the most efficient producers of electricity in the United States. The heat rate we have achieved has been unparalleled in the industry.

These achievements were recently recognized by the Edison Electric Institute, which awarded Duke the Edison Award for 1984. The Edison Award is given annually for "distinguished contribution to the development of the electric light and power industry for the convenience and public benefit of all." Duke was chosen out of the 175 members of the Edison Electric Institute for "superior performance in the design, construction and operation of economical, efficient nuclear power plants, particularly at a time when attention was focused on nuclear plant cost overruns, construction problems and licensing delays."

Finally, the Company is undertaking a program to rehabilitate certain of our older fossil units, representing approximately 997 [90] mw of capacity. These units are no longer reliable because of their age and because their use as peaking units in the past few years has stressed the units, which originally were designed for base load use. The old coal-fired units generally will require repair or replacement of turbine rotors, precipitators and feed water heaters, reinsulation of generator rotors, rewinding of generator stators, retubing of condensers, and many other unit specific refurbishments to make them reliable. We have been operating these units on a "patch and run" basis to avoid major investment in them until McGuire could be completed. Historically, units of this age and condition would be retired and scrapped. We are attempting to rehabilitate the units, however, because we believe that it will be substantially cheaper to rehabilitate them than to build new units as future additions to capacity. We are examining the units to determine at what cost they can be rehabilitated. We hope that many of these units will be able to be rehabilitated at a substantial savings to the retail ratepayers.

* * *

EXHIBIT 18

NORTH CAROLINA UTILITIES COMMISSION

TRANSCRIPT OF TESTIMONY

DOCKET NO: E-7, Sub 391
Vol. 15

DATE July 16, 1985

(2:00-5:30)

[47] CHAIRMAN KOGER: We'll take a five-minute break. Then we'll go to redirect.

(FIVE-MINUTE RECESS)

CHAIRMAN KOGER: We'll come back to order. We'll come back to Duke.

REDIRECT EXAMINATION BY MR. GRIFFITH:

Q Mr. Lee, on cross-examination, you were asked about the retirement dates of the units in the extended coal shut-down program. Do you recall that line of questioning?

A Yes.

Q Would you describe the units that are included in the extended coal shut-down program, and the reasons for their inclusion in it?

A Yes. There are 12 of the units. They include Allen 1, Allen 2, Buck 3, and Buck 4 and 5, Cliffside 1, 2, 3, and 4, Dan River 1 and 2, and Riverbend 6.

These units began to deteriorate, as evidenced by higher maintenance costs, in '81, 82, and '83. And it was realized that to make them available to last into the next century for service, there [48] would have to be major rehabilitation, and the extended coal shut-down study was undertaken.

As a result of that, we find that Allen 1 must have a precipitator replaced. Two of the turbine rotors must be repaired or replaced. We don't know which yet. The feed water heaters need to be replaced. The generator rotor requires reinsulation of the copper, and the boiler has to be modified and upgraded in several areas.

Allen 1 is not available for service and cannot be made available for service.

Allen 2 similarly required replacement of the precipitator. It, too, requires reinsulating of the generator rotor. But in addition, on the generator, the stater must be completely rewound, which means new copper coils, insulation, and the works.

Like Allen 1, it has to have replacement feed water heaters and modifications and upgrading of its boiler. Allen 2 is not available for service at all.

Buck 3 has a condemned generator rotor. By that, it is meant that it is too dangerous to operate under any circumstances. In addition, [49] the generator stater requires rewinding. Rewinding meaning new coils, copper, and insulation. And major replacements of the boiler have to be done at Buck 3. It is not available for service at all.

On Buck 4, again, the generator stater has to be rewound, with new coppper and the associated insulation on the new coils made in the factory and installed in the

field. And the generator rotor must be reinsulated. Major portions of the boiler water walls of the boiler superheater and of the drum circulation system must be replaced.

Also, the condenser tubes must be replaced on the condenser of Buck 4. And this unit is not available for service at all.

On Buck 5, the generator rotor must be replaced due to crack indications in the rotor found by inserting a boroscope inside the hollow rotor shaft and looking at the inside of that forging. And there are indications that tell us that the rotor itself has begun to crack, and we have to replace it.

Major portions of the boiler's water walls, tubes, and the reheater tubes have got to be replaced. [50] Early next year, we're planning additional boroscope examinations of the generator and of the turbine. Buck Unit 5, if not open for these inspections and other repairs, could be made available for limited duty for emergencies only.

Cliffside 1, the condenser must be retubed, and all feed water heaters need to be replaced. And the generator stater has to be rewound. That is, new coils and insulation manufactured and brought and installed in the generator. Cliffside 1, which is 45 years old, is not available for service at all.

Cliffside 2 has the same problems that Cliffside 1 has, but in addition, its generator rotor has to be rewound, in addition to the stater. But like Cliffside 1, requires replacement of the condenser tubes and replacement of all feed water heaters. And Cliffside 2 is not available for service at all.

Cliffside Unite 3. The generator must be rewound. That is, again, new copper coils manufactured and insulated and brought to the field and installed. And the stater of Cliffside – that's the stater. And the rotor of the Cliffside 3 generator [51] must be reinsulated. The shell of the high-pressure turbine is cracked, and it needs to be replaced. That's a very large casting. And all of the feed water heaters must be replaced. Cliffside 3 is not available for service at all.

Cliffside 4, again, requires rewinding of the stater and reinsulation of the rotor, both of the generator, like its sister unit Cliffside 3.

All high-pressure and low-pressure feed water heaters must be replaced. Cliffside 4 is not available for service at all.

Dan River 1 requires replacement of the high-pressure turbine shell – again, that's a casting – and of the turbine rotor. Major portions of the boiler tubes must be replaced. The generator rotor, we've got to either repair or replace some crack indications as found by boroscopy.

Dan River 1 is available for service under extreme emergency conditions.

Dan River 2 is having a new high-pressure shell and a new turbine rotor. The generator rotor is being bored through its middle, to see if we can remove some cracks found by boroscope examination. [52] 'Til we do this, we don't know whether we can save that generator rotor, or whether it must be repaired.

In any event, that generator rotor will have to be reinsulated. Dan River 2 is not available for service at all.

Riverbend 6. There are, again, crack indications in the turbine rotor from borosonic indications. As a result, the manufacturer has recommended severe restrictions on operation of the unit until we know whether we can repair that or have to replace that turbine rotor because of cracks.

The low-pressure feed water heaters have to be replaced, along with major portions of the water wall tubes in the boiler. The generator rotor and the stater must be rewound.

Riverbend 6 is available for service under extreme emergency conditions for only a few times, or we'll lose it altogether.

That completes the report of the status of those twelve units.

Q All right, sir. Do. you know how these units were treated for retirement purposes prior to 1981?

A Yes. It was thought that a number of these units [53] would be retired, and they were in a schedule. In fact, all of them were in sort of schedule.

And I think on cross-examination, it was established that through 1981, our long-range planning department reported to this Commission those units that were scheduled for retirement in the decade thence.

Q All right, sir, did that treatment change after 1981, with respect to the retirement of those units?

A Yes. As I indicated, in '81, '82 and '83, our maintenance estimates were going up very sharply because of

problems like I have just recited to you with respect to those and other units.

It became clear that this group of twelve units would not last until an expected retirement date, but rather had to be taken out of service and rehabilitated in a major way, and therefore, made available to our ratepayers on into the next century.

That was reflected in Mr. W. O. Parker's letter that was cited to me on cross, of November, '82, where he projected that the retirement date for these units would be some time out in the 21st century. I've since talked to Mr. Parker, and [54] he reaffirms my understanding that he was counting on total rehabilitation, or there was no way they could make it that long.

Also, in 1982, we reorganized that area of the company to give more management attention to these problems that were building up in '81 and '82, insofar as keeping these units in service. And we launched in '82 and '83, the study that resulted in the ECS program being approved in early '84.

Q And was that the date that it was implemented?

A Yes.

EXHIBIT 19

DOCKET NO. E-7, SUB 391

BEFORE THE NORTH CAROLINA
UTILITIES COMMISSION

In the Matter of Application by Duke Power Company for Authority to Adjust and Increase Its Electric Rates and Charges	DUKE POWER COMPANY'S PROPOSED ORDER GRANTING RATE INCREASE

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Attorneys for Duke Power Company

August 27, 1985

* * *

has shifted to them a greater portion of the high cost capacity of Catawba, as discussed above.

To summarize our conclusions with respect to the Catawba Sale Agreements, this Commission finds that each of these agreements was prudent when entered into and when restated and amended, and will result in benefits to the North Carolina retail ratepayers. These agreements were necessary to enable Duke to complete Catawba and this Commission approved each of the original agreements. As a result of these agreements, the benefits the North Carolina retail ratepayers are receiving are as follows:

1. Reduced cost of power from the Catawba Nuclear Station to the North Carolina retail ratepayers;

2. Reduced embedded cost of debt and preferred stock to Duke which are being reflected in lower North Carolina retail rates;

3. Avoidance of a portion of the high cost of capacity of Catawba; and

4. Completion of the Catawba Nuclear Station which will provide enhanced system reliability.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this Finding of Fact is found in the testimony of Mr. Lee.

Mr. Lee testified that Catawba Unit 1 will cost approximately $1,700/kw, including AFUDC and the cost of common facilities, which is approximately $915/kw less than the cost of the average nuclear unit expected to come into service in 1985 and lower than the cost of any of those

units. Mr. Lee testified that had Catawba Unit 1 been built at the average cost of a nuclear unit, the North Carolina retail ratepayers would have paid over $901 million in additional rates during the next ten years alone. (Tr. Vol. 3, p. 74) Mr. Lee's testimony was uncontradicted.

Mr. Lee also testified that the sales of Catawba were only a financing arrangement which will not affect the flow of electricity whatsoever. Catawba will serve all of Duke's customers in the same manner as any of Duke's plants. The only effect of the Catawba Sale Agreements is who paid for Catawba and how electricity is priced. (Tr. Vol. 3, pp. 86-87) Mr. Lee's testimony was uncontradicted.

Mr. Lee testified that without Catawba, based on Duke's forecasted peak load for the summer of 1985 of 12,150 MW, Duke would have a generating reserve margin of only 13.4%. With Catawba, Duke's generating reserve margin would be 22.9% based on the forecasted summer 1985 peak. Duke's actual reserve margin for the 1985 summer peak will be 13.6% because of an extended outage at Belews Creek Unit 1 this summer. This compares to a recommended *minimum* reserve margin by this Commission of 20%. Mr. Lee also testified that Catawba will substantially. enhance system reliability. Mr. Lee noted that Duke's newest coal-fired plant is 11 years old and certain of Duke's coal-fired units are already more than 30 years old. By 1995, 57% of Duke's fossil system will be 25 or more years old. Therefore, the addition of Catawba Unit 1 will be vital for continued system reliability. (Tr. Vol. 3, pp. 53-54)

Mr. Lee stated in his testimony that the Company's calculated reserve margin did not include 997 MW of capacity which had been placed in extended cold shutdown

(ECS).This capacity consists of 12 small coal-fired units which are 27 to 43 years old. (Tr. Vol. 3, p. 54) These units were placed into extended cold shutdown because they can no longer provide reliable service and because their use as peaking units in the past few years has stressed the units, which originally were designed for base-load use. Mr. Lee stated that the Company's intention was to thoroughly examine the units and determine whether and at what cost they could be rehabilitated. This process will take approximately three years. From initial examinations, Mr. Lee noted that the units would require repair or replacement of turbine rotors, precipitators and feed water heaters, reinsulation of generator rotors, rewinding of generator stators, retubing of condensers and many other unit-specific refurbishments to make them reliable. (Tr. Vol. 3, p. 74) Nine of the 12 units were not available at the time of the hearing for any service whatsoever and the remaining three units were available only in extreme emergency conditions. (Tr. Vol. 15, pp. 47-53) Mr. Lee stated that because of the length of time needed to examine these units and order the necessary equipment and make the necessary repairs, the units would not be able to be brought back into service until the late 1980's or early 1990's, if at all. (Tr. Vol. 8, pp. 75-77; Tr. Vol. 12, pp. 49-51).

The Attorney General cross-examined Mr. Lee concerning the fact that these units were not shown on Duke's retirement schedule from 1982 on. Mr. Lee testified that many of these units had originally been scheduled for retirement in the 1980's and shown on prior retirement schedules but, because of the increasing costs of new units, Duke had taken the units off of the retirement schedule in anticipation that they would be rehabilitated through the extended cold shutdown program. (Tr. Vol. 10, p. 41; Tr.

Vol. 15, pp. 52-54) The Attorney General also cross-examined Mr. Lee concerning the availability of these units in 1983. Attorney General-Lee Cross Examination Exhibit 9 showed that these units were available in 1983 between 59% and 97% of the time. Mr. Lee testified that this showed only the availability of the units for dispatch and reflected the fact that the units were called on infrequently. If the units had been called on more frequently they may not have run and their availability would have been lower. (Tr. Vol. 10, pp. 51-55)

Mr. Lee also testified concerning the summer 1985 peak load forecast of 12,150 MW. Mr. Lee stated that the forecast had been made in September of 1984 for budgetary purposes. It is this short-term forecast made in September of each year upon which the Company plans its budget for the following fiscal year. Mr. Lee stated that a similar forecast is made every year and that this forecast is the most accurate forecast the Company has for the next fiscal year. Mr. Lee testified that this forecast was higher than the previous forecast shown in the Company's previous short-range load forecast because. that forecast was made in 1983. The 1983 forecast was made shortly after the bottom of a recession and incorporated a lower growth rate in the economy than had actually occurred since that time or was expected to occur in the near future. The September 1984 forecast was based upon the more current economic conditions prevailing at that time. Therefore, Mr. Lee testified that the September 1984 forecast was the most reliable forecast for prediction of the summer 1985. (Tr. Vol. 15, pp. 54-56)

This Finding of Fact is also supported by the testimony of Public Staff witness Lam. Mr. Lam testified that Catawba Unit 1 did not represent excess capacity because

even with Catawba Unit 1 and including the units which have been placed in extended cold shutdown, Duke had a reserve margin of only 25.5% based upon the actual winter peak load experienced in January of 1985. Mr. Lam testified that use of Duke's actual peak load was appropriate because the Company has to meet whatever the largest peak is on its system and that naturally occurs, during extreme weather conditions. (Tr. Vol. 24-B, pp. 98-104)

Witnesses for the Attorney General, and CIGFUR and Wells Eddleman, representing himself, testified that Catawba Unit 1 was excess capacity and not needed at this time. Dr. Wilson gave the following reasons for his conclusion that Catawba Unit 1 represented excess capacity: (1) the 997 MW of capacity placed in extended cold shutdown should be included in the calculation of reserves; (2) Catawba was base load capacity coming on at a time when the addition of cycling capacity is more appropriate; and (3) Duke's load forecast made in September 1984 was high in comparison to the 1983 load forecast. (Tr. Vol. 25-B, pp. 85-92)

Dr. Wilson's conclusion that the units placed in extended cold shutdowns should be included in the calculation of reserve margins was based upon the testimony of Attorney General witness Whitfield Russell. (Tr. Vol. 25-B, p. 87) Mr. Russell testified that these units should be included in the reserve margin because they were capable of providing service. (Tr. Vol. 25-A, p. 10) Upon cross-examination, however, Mr. Russell was unable to state when these units could be made available for reliable service. Mr. Russell did not know whether they could be made available for service within a period of two years or longer. (Tr. Vol. 25-A, pp: 69, 89-90, 95-97, 102-103) Mr.

Russell admitted that he had not examined the units placed in extended coal shutdown; rather, Mr. Russell stated that his conclusions were based upon an examination performed by Mr. Walter Gunderson. (Tr. Vol. 25-A, pp. 73, 106) Mr. Gunderson was not offered as a witness by the Attorney General. Duke subpoenaed Mr. Gunderson to testify but that subpoena was not mandatory since it was addressed to Mr. Gunderson outside North Carolina, and Mr. Gunderson did not appear. Mr. Russell testified that the Attorney General had refused to advise Mr. Gunderson whether or not to honor the subpoena. (Tr. Vol. 25-A, pp. 61-62). Mr. Gunderson's report on the extended cold shutdown program was introduced into evidence, however. Mr. Gunderson's report concluded that "[t]he [extended cold shutdown] program, as presently conceived, is a prudent action that is carefully designed to reduce operating costs while retaining operating flexibility; based on the projected Load/Capacity situation in the Duke Control Area." (Russell Exhibit 3).

Mr. Russell also testified that Duke could have rehabilitated the extended cold shutdown units prior to the commercial operation of Catawba Unit 1. On cross-examination, however, he could not state when Duke would have had sufficient capacity to remove these units for the period of time that it would take to rehabilitate them. (Tr. Vol. 25-A, pp. 71-72, 108) Indeed, as discussed above, he had no knowledge concerning the length of time it would take to rehabilitate these units.

Dr. Wilson's conclusion that the addition of cycling capacity rather than base load capacity was more appropriate at this time was based in part on his finding that Catawba Unit 1 could operate only 4,000 hours per year without replacing generation from Duke's Belews Creek

and Marshall units. Dr. Wilson testified that this would have a negative effect because Belews Creek and Marshall are the most efficient coal-fired units in the country. (Tr. Vol. 25-A, p. 90) With respect to this matter, Mr. Lee testified that the conversion of coal-fired units from base load to cycling duty was an inevitable result of the aging process, and this had been the pattern of every coal fired unit Duke had ever built. (Tr. Vol. 10, p. 32)

CIGFUR Witness Falkenberg also testified that Catawba Unit 1 was excess capacity. His conclusion was based upon the assumption that the extended cold shutdown units could provide reliable service. (Tr. Vol. 31, p. 99) Mr. Falkenberg admitted on cross-examination that he had performed no independent analysis of the extended cold shutdown program. Rather, his conclusion that the units could provide service was based entirely upon his reading of Mr. Lee's testimony. (Tr. Vol. 32, pp. 44-45) He acknowledged that he would also accept any testimony Mr. Lee gave at the hearing, but he was unaware that Mr. Lee. testified on redirect examination that the ECS units would be out of service for several years. (Tr. Vol. 32, pp. 45-46) Mr. Falkenberg also stated that he had assumed in his conclusion that a reserve margin of 15% was adequate, and that reserves beyond 15% would begin to be excess. (Tr. Vol. 32, p. 44)

Mr. Eddleman also based his conclusion that Duke had excess capacity on the assumption that the extended cold shutdown units should be included in Duke's reserve margins. Mr. Eddleman also had made no examination of the extended cold shutdown units. Mr. Eddleman contended that these units should have been rehabilitated but he did not state when Duke should or could have rehabilitated these units. (Tr. Vol. 27, p. 203)

Mr. Eddleman also contended that Duke's September 1984 load forecast for the summer 1985 peak was too high. He suggested that the Commission use the forecast prepared by the Carolina Environmental Study Group as well as a forecast prepared by himself which show a 1985 summer peak for Duke in the range of 11,000-11,500 MW. Mr. Eddleman did not state what assumptions contained in Duke's September 1984 forecast were incorrect, however. (Tr. Vol. 27, pp. 204-205)

Finally, Mr. Eddleman testified that Duke has excess base load capacity. He suggested that if Duke needs new capacity it should be cycling or peaking capacity rather than base load capacity. (Tr. Vol. 27, pp. 207-211)

We conclude that it is inappropriate to include the extended cold shutdown units in the calculation of Duke's current reserve margin. First, Mr. Lee's testimony concerning the condition of these units is uncontradicted. It is clear to this Commission that these units cannot provide reliable service until major repairs can be performed which will take a number of years. It would be inappropriate to include in Duke's reserve margins plants which cannot run and will not be able to run for a number of years. Second, we conclude that the only way that these units can be rehabilitated so as to extend their life for a number of years is through a comprehensive program such as the extended cold shutdown program. Ordinarily, plants of this age and condition are retired and replaced by new capacity. If this program can successfully rehabilitate these units, the units will be able to replace expensive new capacity which otherwise would have to be built. Therefore, we find, as did the only expert employed by any of the intervenors to examine the condition of these units, Mr. Walter Gunderson, that the extended cold shutdown

program is prudent and designed to minimize costs to the retail ratepayers. This Commission notes that any decision which it would make that would discourage such a program would not be in the best interests of the retail ratepayers because over the long term it would increase costs by forcing the utilities to run older units until they cannot be rehabilitated and thus force utilities to build new capacity rather than rehabilitating older, lower cost capacity.

This Commission also concludes that Duke's September 1984 forecast of its summer 1985 peak of 12,150 MW is the appropriate forecast to use in determining Duke's reserve margin for the summer of 1985. That forecast is based, upon the most recent information available to Duke at the time at which it was made and is based upon the economic conditions likely to prevail during the period of time it covers. No party has shown any invalid or improbable assumptions which were included in the September 1984 forecast.

With respect to the contention that Catawba Unit 1 represents excess base load capacity, we note that even Dr. Wilson admits that Catawba Unit 1 may be able to run with a capacity factor of almost 50% without displacing generation from Duke's Marshall or Belews Creek Units. The average capacity factor in the United States of a unit of comparable size to Catawba Unit 1 is only 57% and thus the amount of generation displaced from Marshall and Belews Creek is likely to be minimal. Furthermore, we note that the conversion of base load coal units to cycling duty is a natural result of the aging of such units. The running costs of nuclear units such as Catawba Unit 1 are substantially below the running costs of any coal-fired unit, including Marshall and Belews Creek.

Therefore, this Commission concludes that none of the parties has presented competent evidence to support their position that Catawba Unit 1 represents excess capacity and we find that Catawba Unit 1 is needed. We note that this Commission in its April 1985 "Analysis for Long Range Needs for Expansion of Electric Generation Facilities in North Carolina" found that Duke's construction schedule, which included Catawba Unit 1 coming on line in 1985, would not result in excessive reserve margins. Nothing has changed since that time which would cause us to change our minds.

We think it is also important to note here that all of the intervenors who have alleged that Duke has excess capacity appear to base this conclusion in part upon an assumption that Duke should have at all times only a hypothetical optimum reserve margin. This Commission has recommended a *minimum* reserve margin of 20%. This Commission has never stated that a utility should have a reserve margin of no more than 20%. In fact, just the opposite is true. This Commission has repeatedly recognized in its Analysis of Long-Range Needs for Electric Generating Facilities in North Carolina that forecasting electricity needs for many years into the future is at best imprecise and that the long lead times required to bring capacity on line makes planning difficult. We have also recognized that planning for future electric consumption can vary within a range of forecasted values. Furthermore, we have recognized that the addition of large base load units such as Catawba Unit I will inevitably have a major impact on a utility's reserve margins. Finally, Catawba Unit 1 has been under construction for more than twelve years. To be able to predict its need that long into the future and come as close to the minimum reserve margin

is certainly a commendable accomplishment. It is not the position of this Commission that a utility can recover the costs of a unit when it comes into service only if, in hindsight, that unit results in optimum reserve levels at the precise time it comes into service. Such a policy would penalize utilities for prudent decisions and would discourage investment in new generating facilities necessary for continued growth in this State which is contrary to the policies of this Commission and of this State.

* * *

EXHIBIT 21

NORTH CAROLINA UTILITIES COMMISSION

TRANSCRIPT OF TESTIMONY

DOCKET NO. E-7, Sub 408

DUKE ROWER COMPANY

Volume 5

DATE September 3, 1986

CONFIDENTIAL
2LL 0000136

[32] Q. MR. LEE, IN DOCKET NO. E-7, SUB 391, YOU DESCRIBED THE EXTENDED COLD SHUTDOWN (ECS) PROGRAM INVOLVING SEVERAL OLD FOSSIL GENERATING UNITS. WHAT IS THE CURRENT STATUS OF THE ECS PROGRAM?

A. I testified in our last case that in March 1984 we began our Extended Cold Shutdown program. We removed from service twelve small coal-fired units, ranging in age from 27 to 43 years, which totaled 997 MW of capacity. These units were placed in extended cold shutdown because they could no longer provide reliable service as a result of their age and condition. Rather than retire the units, we adopted the ECS program to rehabilitate them and extend their lives.

When we began removing these units from service in March 1984, we placed them in protected shutdown status while we performed plant evaluations and upgrade and reliability studies to determine precisely the work that

needed to be done, and organized ourselves to accomplish that work. We are now well under way toward modernizing these units. In fact, we completed the major work on Dan River Unit 2 and returned it to service in January 1986. This work at Dan River Unit 2 included replacement of the turbine high pressure rotor and shell, boresonic analysis and overbore of the generator rotor, and rehabilitation of the boiler economizer, superheater and wall tubes. Dan River Unit 2 has returned to service with extended life.

Because we have changed the emphasis of our effort from protection to refurbishment, we have changed the name of the program from ECS to Plant Modernization Program (PMP). The new name more accurately describes where we are in the process.

[33] At the present time we have completed the detailed upgrade studies at Dan River and at the Allen Steam Station. We made a decision to evaluate all of the units at the various stations while we had the evaluation teams on site. This detailed evaluation of all units will be helpful to us currently as we maintain those units that are in service.

During 1986 the major PMP work will be at Dan River 1, Buck 5, Riverbend 6, and Allen 1. Dan River 3 was placed in the PMP program in January, 1986. Although the upgrade studies have not been completed at each of these units, we are proceeding with certain work that is identified in unit evaluations and is generally common to each unit, including, as necessary, turbine high pressure rotor and shell replacement, boresonic analysis, generator and turbine rotor overbore, boiler tube rehabilitation, and precipitator and feedwater heater replacement.

We are continuing to do the bulk of this work with our own employees, and expect the overall cost of refurbishing the PMP units to be $200-300 per kilowatt. We expect to gradually return additional units to service as the refurbishments are completed.

We are unable to state precisely when the refurbishment work can be completed on each unit. Many of the parts and equipment needed in the refurbishment must be manufactured specifically for the units. This requires lead times ranging from several months for some items, to as much as 36 months for major components like a new rotor. In addition, we are doing this refurbishment work with Duke employees, which we believe is the most cost-effective method.

[34] The obvious benefit of PMP is that we add capacity at very reasonable cost. But there is another very important benefit that will become increasingly important in the years ahead. The Duke coal-fired capacity is aging. Our Marshall Station is now 20 years old and Belews Creek, our newest, is already 11 years old. By 2000, all of our coal-fired capacity will be more than 25 years old. Our employees are learning a great deal from the present refurbishment and life-extension efforts which will help us maintain our other units better, and will also make us ready to meet the future challenge of extending the life of other units on a cost effective basis.

Q. MR. LEE, YOU HAVE TESTIFIED IN THE PAST ABOUT THE EFFECT OF COST OF SERVICE SAVINGS AND THE COMPANY'S EFFICIENCY ON RATES. IS THE COMPANY CONTINUING ITS EFFORTS TO REDUCE COST OF SERVICE AND OPERATE EFFICIENTLY?

A. Yes. I have previously stated that our rates are low compared to other utilities, reflecting the efficiencies we have achieved in the past. I testified in the last case that in 1984 our employees operated the most fuel-efficient, coal-fired power plants in the country for the eleventh year in a row. Industry statistics for 1985 are not yet available, but our coal-fired stations improved in efficiency in 1985 over 1984. In fact, for 1985 our coal-fired stations exceeded the national efficiency record which was set by Duke Power in 1976. I expect we will learn that our 1985 fossil performance efficiency set a new all-time record for the United States, which is a remarkable achievement with machinery ranging from 11 to 38 years old, and a tribute to the outstanding efforts of the Duke people who did it.

* * *

EXHIBIT 22

February 1, 1985

Memorandum for File

Subject: Fossil Units – Extended Cold Shutdown

During 1984 a management decision was made to remove 12 older coal-fired units from Duke's stated system net capability because of their age (27-43 years) and condition. An evaluation and decision is to be made at a later time if and when it will be cost effective to bring these units back into service. Planning must encompass necessary plant modifications and maintenance to make these units reliable if they return to service.

Effective 12:01 a.m. March 1, 1984, the following small coal-fired units are removed from the stated system net capability:

Unit	Age	Net Capability
Buck Unit 3	42 yrs.	70MW
Buck Unit 4	41 yrs.	38MW
Buck Unit 5	31 yrs.	128MW
Cliffside Unit 1	43 yrs.	38MW
Cliffside Unit 2	43 yrs.	38MW
Cliffside Unit 3	35 yrs.	61MW
Cliffside Unit 4	35 yrs.	61MW
Dan River Unit 1	34 yrs.	65MW
Dan River Unit 2	33 yrs.	65MW
Riverbend Unit 6	29 yrs.	133MW
Allen Unit 1	27 yrs.	150MW
Allen Unit 2	27 yrs.	150MW
Total Fossil Production		997MW

Effective December 31, 1984, book cost and additions of the above units were transferred from Account 101 – Plant in Service to Account 105 – Plant Held for Future Use.

The dollar amount moved was $135,052,961. For accounting clarity, the associated depreciation reserve was moved to a separate account. Moving these dollars had no impact on rate base since the units were fully depreciated. However, annual depreciation expense has been reduced by $4,821,391.

As of this date, procedures have been developed, some equipment purchased and installed to commence implementation of a comprehensive extended cold shutdown program. Management is confident the program, which has been developed and demonstrated on the first units, represents a cost effective approach to preserving future options for these small coal-fired units.

/s/ H.D. Whitley
H.D. Whitley

HDW/mdh

EXHIBIT 23

Duke Power Company
Fossil Production Department
Plant Modernization Project
Project Review
April 24, 1989

I. PMP Philosophy

II. Schedule Review and Status

III. Cost Review

- Projections
  - PMP Total
  - Buck 3 & 4/Cliffside 1-4
  - Specific Equipment
  - Break even Capital Cost
  - Spent to Date

IV. Capacity Factors

- Buck 3 & 4/Cliffside 1-4

V. Discussion

Duke Power Company
Fossil Production Department
Plant Modernization Project
PMP Philosophy

Purpose

To conduct maintenance and upgrade to selected fossil generating units so that they operate safely, reliably and cost effectively for an additional 20 years.

Plan/Criteria

- Removed from stated capacity – not available for dispatch
- Protect against further deterioration
- Maintain, review and update major work activities list periodically
- Accomplish work activities which:
  - are cost effective
  - have impact on availability (target 80-85%)
  - replace worn out, obsolete equipment
  - improve operability
  - meet regulatory requirements
  - are necessary before the next major outage
- Schedule work to levelize resources
- Delay expenditures as late as possible
- Capitalize all expenditures

Duke Power Company
Fossil Production Department
Plant Modernization Project

Schedule	Review		
March	1984	-------	Twelve units placed into extended cold shutdown
June	1984	-------	Scheduled all units to return to service prior to 1992

January	1986	- - - - - - - -	Returned Dan River 2 to service; place Dan River 3 into PMP
April	1986	- - - - - - - -	Revised schedule to return all units to service prior to 1994
October	1986	- - - - - - - -	Placed Riverbend 7 into PMP
January	1987	- - - - - - - -	Returned Dan River 1 to service
August	1987	- - - - - - - -	Placed Riverbend 4 into PMP
April	1988	- - - - - - - -	Revised schedule to return all units to service prior to 1992

Schedule – Near Term

June	1989	- - - - - - - -	Return Dan river 3 to service
October	1989	- - - - - - - -	Return Allen 2 to service (available 08/89)
June	1990	- - - - - - - -	Return Allen 1 to service
June	1990	- - - - - - - -	Return Riverbend 4 to service

EXHIBIT 25

February 13, 1986

TO: W. H. Owen
J. M. Hart
R. W. Bostian
R. L. Dick
G. W. Grier
R. B. Priory
R. J. Osborne

SUBJECT: Plant Modernization Project Strategy Statement

We have revised the PMP Strategy Statement to read as follows:

> The Plant Modernization Project includes the rehabilitation and upgrading of thirteen (13) coal-fired units totaling approximately 1,000 megawatts capacity. The modification will be completed during the next approximate six years with selected unites returned to service as the work is completed. The extended operating life of the rehabilitated units is a cost-effective alternative to the addition of new capacity. The PMP provides reliable and efficient generating capability from older and smaller units that are returned to service in increments to increase our system generating capability. Several modifications will enable the PMP units to better accommodate the cyclic duty they will experience during their remaining operating life.

/s/ William O. Parker, Jr.
William O. Parker, Jr.

MHG:kk

cc: G. O. Managers
Station Managers

EXHIBIT 26

DUKE POWER COMPANY

DIRECT TESTIMONY

NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 487

APRIL 12, 1991

TESTIMONY OF

WILLIAM S. LEE

FOR

DUKE POWER COMPANY

NCUC DOCKET NO. E-7, SUB 487

Q. PLEASE STATE YOUR NAME, ADDRESS AND YOUR POSITION WITH DUKE POWER COMPANY.

A. My name is William S. Lee. My business address is 422 South Church Street, Charlotte, North Carolina 28242. I am Chairman of the Board and President of Duke Power Company and a registered professional engineer in North Carolina and South Carolina.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the rate increase that we are seeking and certain other matters which are of importance to the Commission. We are seeking an increase of 9.2%, or approximately $223 million, based on the test year which is the twelve months ended December 31, 1990. Of this requested increase, about 6% relates to the inclusion of the cost of the Bad Creek Hydroelectric Station in our rates. The remainder is caused by a number of other cost increases which have

occurred since 1985, the test year of our last general rate increase. These costs must be reflected in our electric rates if the Company is to have a reasonable opportunity to earn a fair and reasonable return on investment.

Q. MR. LEE, PLEASE OUTLINE YOUR TESTIMONY.

* * *

[5] Duke has also continued its plant modernization program. This is a program for our older coal fired units which was begun in 1985 to allow those units to operate well beyond their expected retirement at the end of their initial design life. Since January 1, 1987, we have brought back on line five units with a generating capacity of 618 MW. This capacity has been brought back with an average additional investment of $164 per kw, a small fraction of the cost to build a new coal-fired plant today. We expect to bring back additional units in 1991.

We have also increased our demand side efforts to lower the rates of growth in our peak demand and to promote off-peak sales. These efforts have slowed the peak demand growth we otherwise would have experienced and enabled us to avoid the addition of new generating facilities for five years in a service territory which has experienced continued economic growth. These efforts also allow us to spread our fixed production costs over a greater number of kwhs. An example of our efforts to promote off-peak sales is a recent sale of a heat Recovery Opportunity system to one of Duke's textile customers. This system will substantially increase the customer's heat recovery process, lower waste water discharge temperatures and save the customer over $20,000 each year. It will also provide

Duke with 572,000 additional kwhs of sales each year, mostly during non-peak hours.

* * *

EXHIBIT 40

PROJECT OUTAGE TABLE
Boiler Work over $500,000

Project	Unit Put Into ECS for PMP	Not Available for Dispatch per GADS	Boiler Work
AS 5 2000		01/15/00 - 05/14/00	01/15/00 - 05/14/00
AS5 1996		04/18/96 - 06/21/96	04/18/96 - 06/21/96
AS4 1996		01/26/96 - 04/12/96	01/26/96 - 04/12/96
AS4 1998		08/29/98 - 01/19/99	08/29/98 - 01/19/99
AS2 1988 (PMP)	03/01/84 (ECS)	04/05/85 - 04/25/89	06/22/97 - 03/02/89[1]
AS1 1989 (PMP)	03/01/84 (ECS)	03/28/85 - 08/13/90	Jan. 1989 - Dec. 1989[2]
BC2 1999		02/26/99 - 05/19/99	02/26/99 - 05/19/99
BC2 1996		01/27/96 - 04/10/96	01/27/96 - 04/10/96
BC1 2000		02/11/00 - 05/19/00	02/11/00 - 05/19/00

[1] *See* Bates No. BL-4 0002614; BL-4 0002748.

[2] *See* Bates No. 30B5R(1) 0007070.

BK5 1991 (PMP)	03/01/84 (ECS)	10/01/85 - 06/01/91	10/07/85 - 09/11/86[3] 04/04/89 - 12/27/89[4]
BK4 1994 (PMP)	03/01/84 (ECS)	10/09/83 - 11/01/94	07/23/92 - 07/05/94[5]
BK3 1994 (PMP)	03/01/84 (ECS)	01/01/84 - 07/01/94	03/18/92 - 02/01/94[6]
MS4 1990		10/08/90 - 12/22/90	10/08/90 - 12/22/90
MS3 1999		09/04/99 - 12/10/99	09/04/99 - 12/10/99
MS2 1989		08/16/89 - 01/03/90	08/16/89 - 01/03/90
MS2 1996		09/20/96 - 11/27/96	09/20/96 - 11/27/96
CS2 1993 (PMP)	03/01/84 (ECS)	07/15/84 - 02/01/94	05/20/91 - 06/07/93[7]
CS3 1990 (PMP)	03/01/84 (ECS)	03/28/85 - 12/02/91	01/02/90 - 08/27/90[8]
CS4 1990 (PMP)	03/01/84 (ECS)	03/28/85 - 04/09/91	10/29/90 - 1/31/91[9]

[3] *See* Bates No. BK 0033150; BK 0033151.

[4] *See* Bates No. BK 0037406.

[5] *See* Bates No. BK 0015609; BK 0015607.

[6] *See* Bates No. BK 0011854; BK 0011907.

[7] *See* Bates No. BL-1 0003034; BL-1 0003016.

[8] *See* Bates No. BL-6 0006983; BL-6 0007018.

[9] *See* Bates No. BL-2 0011877.

CS5 1992/1995		04/04/92 - 05/27/92 03/26/95 - 06/08/95	04/04/92 - 05/27/92 03/26/95 - 06/08/95
CS1 1993 (PMP)	03/01/84 (ECS)	10/02/84 - 06/01/94	03/03/92 - 11/29/93[10]
DR3 1988 (PMP)	01/01/86 (PMP)	10/30/85 - 04/19/89	Jan. 1988 - Feb. 1989[11]
AS3 1994		08/26/94 - 12/07/94	08/26/94 - 12/07/94
LS3 1989/1990		09/28/89 - 06/17/90	09/28/89- 06/17/90
RB4 1990 (PMP)	08/01/87 (PMP)	11/01/87 - 05/11/90	07/19/88 - June 1989[12]
RB6 1991 (PMP)	03/01/84 (ECS)	09/23/85 - 06/18/91	12/21/88 - 1/18/91[13]
RB7 1992 (PMP)	10/01/86 (PMP)	10/21/86 - 08/01/92	01/23/90 - 08/29/91[14]
BK6 1990		09/04/90 - 10/15/91	09/04/90 - 10/15/91
MS1 1992		10/05/92 - 12/23/92	10/05/92 - 12/23/92

[10] *See* Bates No. GO13 0000827; BL-1 0003016.

[11] *See* Bates No. 30B5R(1) 0007071.

[12] *See* Bates No. GO12 0003048; RB0013656.

EXHIBIT 57

DUKE POWER COMPANY
TRAINING AND REFERENCE GUIDE

FOSSIL ENVIRONMENTAL COMPLIANCE

VOLUME 2
AIR QUALITY

[LOGO]

SEPTEMBER 30 – OCTOBER 1, 1991

NEW SOURCE REGULATION

Confidential
BK 0000913

Legislative Background:

- Clean Air Act Amended in 1977 and 1979.
- Two Key Requirements Affecting Emission Sources
  - New Source Performance Standards (NSPS)
  - Prevention of Significant Deterioration (PSD)
- Purpose: Preserve Air Quality Better Than NAAQS
- Rationale:
  - Environmental Protection Should Be Considered As Part of Business Decisions To Build New Or Expanded Facilities.
  - Contrast Existing Facilities: Decision To Build Made In Good Faith In Absence Of Control Requirement.

Requirements for NSPS:

- Technology-Based Standards
- Standard Is Minimum Acceptable Technology For New Sources (PSD May Supercede)
- Triggered By:
  - Construction of New Source
  - Reconstruction of Existing Source (50% Rule)
  - Modification of Existing Source Which Increases Hourly Emissions At Maximum Load
- Standards For Most Major Industrial Processes: 40 CFR 60, Attachment 2
- Potential Duke Sources At Fossil Stations:
  - Fossil-Fired Utility Boilers
  - Industrial Boilers > 100 mBtu/hr (Auxiliary Boilers)
  - Combustion Turbines

Requirements for PSD:

- Ambient Air Quality Standard: Sets Increment For Maximum Allowable Deterioration/ Restricts Growth
- Based On:
  - Annual Emissions From Facility
  - Net Emissions Increase (Contemporaneous Reductions Will Help).

- New Or Modified Emissions Sources Subject To "Best Available Control Technology" (BACT) Review

New Sources In Non-Attainment Areas:

- No New Emissions Source Allowed Without Offsets From Existing Sources (For the Non-Attainment Pollutant)
- Source Must Install Lowest Achievable Emission Rate (LAER) Technology

* * *

II.
EVALUATING PLANT MODIFICATIONS/ RECONSTRUCTION THAT COULD TRIGGER NSPS AND/OR PSD REQUIREMENTS

A. Contact fossil Environmental Compliance (FEC) for support in evaluating New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD), and notification requirements BEFORE. . . .

1. Making ANY physical or operational changes that increase emission rates or annual emissions of national ambient air pollutants (SO_2, NO_x, particulate, VOC (in ozone non-attainment areas) etc.) to the atmosphere.

   a. Add a new permittable source

   b. Modify a permitted source

      – increase maximum permitted heat inputs – replace an exempt fuel-burning source with a larger one (NC: >100 mmbtu/hr) that requires a permit

- increase use of permitted fuels by modifying
    - air supply/exhaust fans
    - burner arrangements
    - increased mail capacity

c. Modify/Replace permitted air cleaning system rendering it less efficient and/or different system from that permitted

- decreased plate surface area
- alter hopper baffle design (e.g. Allen 3, 4, and 5; Marshal 3 and 4)
- use of unpermitted abatement system or component (ex. Allen 3, 4, 5 cold-side)

d. Use of unpermitted fuels (see air toxics section IV)

2. Plant reconstruction (replacement of components) such that fixed capital cost of replacement components exceeds 50% of capital cost required for a comparable new facility.

a. Rebuild auxiliary boiler that is > 100mmbtu/hr

b. Replace existing CT components

B. Modifications EXEMPTED from NSPS

1. Routine maintenance, repair and replacement that does not expand the facility

2. An increase in the production rate accomplished w/o a capital expenditure

3. Increased hrs of operation

4. Use of an alternative fuel provided the facility was designed to accommodate this fuel before NSPS standards

5. Replacement/addition of an air abatement system that is equally or more beneficial to air quality

C. How to protect an existing station's exemptions from NSPS and PSD requirements?

NSPS:

1. EPA will evaluate a units maximum emissions over the past 5 yrs.

2. Duke should demonstrate/document that a unit has been capable of its maximum capability to avoid loosing capacity.

   a. Recommend station conduct annual review/documentation of actual vs. maximum design capacity.

   b. Recommend short-order repair of damaged, deteriorating equipment as indicated from annual reviews.

PSD:

1. A PSD review is triggered if annual emissions increase due changes in the unit:

   a. an increase in the maximum net dependable capacity of the unit

      - dispatcher operates the unit at a higher load

      - unit operated more frequently

b. PSD not triggered by an increased generating (w/o any changes to unit)

EXHIBIT 73

[LOGO] UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF AIR AND RADIATION

(Filed Sep. 9, 1988)

MEMORANDUM

SUBJECT: Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the Wisconsin Electric Power Company (WEPCO) Port Washington Life Extension Project

FROM: Don R. Clay, Acting Assistant Administrator for Air and Radiation (ANR-443) [/s/ DNY]

TO: David A. Kee, Director
Air and Radiation Division, Region V

This is in further response to your March 25, 1988 memorandum requesting guidance on PSD applicability regarding the proposed renovation of the Port Washington Power Plant by the WEPCO. I have also addressed the question whether the renovations proposed for this facility would subject the individual units to Subpart Da of the NSPS.

Based on the information presented in your memorandum, subsequent written information received from WEPCO, information provided by the State of Wisconsin, and other information contained in the Environmental Protection Agency's (EPA's) files on this matter, I have concluded that, as proposed, this renovation project would

not come within the PSD and NSPS Exclusions for routine maintenance, repair, and replacement, nor the exclusions for increases in production rate or hours of operation. It also appears that the project would increase emissions within the meaning of these two programs. Thus, the renovation project likely would be subject to PSD review as a major modification of an existing stationary source and that the renovations proposed for units, 1-5 at this facility probably would subject the individual units to Subpart Da of the NSPS as a modification. However, WEPCO has not yet requested EPA to make an applicability determination. In any case, it would not be possible to make final applicability determinations at this point, for three basic reasons.

First, EPA must be supplied sufficient data regarding the various pollutants emitted by the Port Washington facilities to determine, on a pollutant-specific basis, how the proposed renovations would affect emissions levels. Second, WEPCO might avoid both PSD and NSPS applicability by adding or enhancing pollution control equipment, or in the case of PSD, restricting operations below maximum potential such that the emissions increases necessary to trigger applicability would not occur. The WEPCO should discuss its plans in this regard with EPA. Third, regarding NSPS applicability to unit 1, additional information is necessary to determine whether a physical or operational change would occur.

Thus, although this memorandum will serve to answer many of the questions necessary to reaching final determinations, you should advise WEPCO that ultimately applicability depends upon changes in emissions after the renovations and whether the company decides to take the steps which would enable it to lawfully avoid

coverage. Also, NSPS coverage of unit 1 can only be determined after an evaluation of the additional information regarding the work to be performed. In addition, as to NSPS, WEPCO should be advised to submit a formal request pursuant to 40 CFR 60.5 if it desires a final applicability determination.

As the need for further factual development here suggests, determinations of PSD and NSPS applicability are fact-specific, and must be made on a case-by-case basis. This memorandum provides a framework for analyzing the proposed changes at Port Washington and gives EPA's views on relevant issues of legal interpretation. It should also be useful in assessing other so-called "life extension" projects in the future. However, any such project would need to be reviewed in light of all the facts and circumstances particular to it. Thus, a final decision regarding PSD and NSPS applicability here would not necessarily be determinative of coverage as to other life extension projects.

If you have any further questions regarding the discussion or conclusions in this memorandum, please have your staff contact David Solomon of the New Source Review Section at FTS 629-5375.

I. Background

As mentioned in your March 25 request, the five coal-fired units at Port Washington began operation in 1935, 1943, 1948, 1949, and 1950, respectively. Each unit was, initially rated at 80 megawatts electrical output capacity. In recent years, however, the performance of the units began to deteriorate due to age-related degradation of the physical plant. In particular, inspections performed by a

WEPCO consultant in 1984 revealed extensive cracks originating from the internal surfaces of the rear steam drums and boiler bank boreholes in units 2, 3, 4, and 5, creating significant safety concerns. Because of these safety concerns and other age-related problems, in 1985 the operating levels of units 2, 3, and 4 were reduced, and unit 5 was removed from service. As a result of the plant's deteriorating condition, the maximum rated physical capacities of units 1, 2, 3, and 4 at this time are 45, 65, 75, and 55 megawatts, respectively.

The life extension project includes extensive capital improvements to the common facilities and each of the individual units, including replacement of the rear steam drum in units 2, 3, 4, and 5. The renovation work will restore the physical and operational capability of each unit to its original 80 megawatt nameplate capacity, and extend the useful life of the units well beyond the planned retirement dates that would otherwise apply. Upon completion of the project, WEPCO intends to substantially increase the actual operations at the Port Washington plant.

II. PSD Applicability

The life extension project at Port Washington is subject to preconstruction review and permitting under the Act's PSD provisions if it is a "major modification" within the meaning of the Act and EPA's regulations., The PSD regulations at 40 CFR 52.21 govern this determination because Wisconsin has been delegated PSD permitting authority under the provisions of 52.21(u). The definition of "major modification" in 52.21(b)(2)(i) requires an analysis of several factors. These factors may be

grouped under two general questions. Will the work entail a "physical change in or change in the method of operation of a major stationary source"? If so, will the change "result in a significant net emissions increase of any pollutant subject to regulation under the Act" [see 52.21(b)(2)(i)]? The Port Washington facility is an existing major stationary source because it emits well in excess of the PSD threshold amount for several pollutants.

A. Physical Change or Change in the Method of Operation

This requirement of a major modification is satisfied if either a physical or operational change would occur.

1. Physical Change

The renovation work called for under the proposed life extension project at Port Washington would constitute a "physical change" at a major stationary source. The clear intent of the PSD regulations is to construe the term "physical change" very broadly, to cover virtually any significant alteration to an existing plant. This wide reach is demonstrated by the very narrow exclusion provided in the regulations: other than certain uses of alternate fuels not relevant here, only "routine maintenance, repair and replacement" is excluded from the definition of physical change [see 52.21(b)(2)(iii)(a)].

In determining whether proposed work at an existing facility is "routine," EPA makes a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors, to arrive at a common-sense finding. In this case, all of these factors suggest that the work required under WEPCO's life

extension project appears not to be "routine." The available information indicates that the work proposed at Port Washington. is far from being a regular, customary, or standard undertaking for the purpose of maintaining the plant in its present condition. Rather, this is a highly unusual, if not unprecedented, and costly project. Its purpose is to completely rehabilitate aging power generating units whose capacity has significantly deteriorated over a period of years, thereby restoring their original capacity and substantially extending the period of their utilization as an alternative to retiring them as they approach the end of their useful physical and economic life. The most important factors that would support these conclusions are outlined below.

a. The project would involve the replacement of numerous major components. The information submitted by WEPCO shows that the company intends to replace several components that are essential to the operation of the Port Washington plant. In particular, as noted above, WEPCO would replace the rear steam drums on the boilers at units 2, 3, 4, and 5. According to WEPCO, these steam drums are a type of "header" for the collection and distribution of steam and/or water within the boilers. They measure 60 feet long, 50.5 inches in diameter, and 5.25 inches thick, and their replacement is necessary to continue operation of the units in a safe condition. In addition, at each of the emissions units, WEPCO plans to repair or replace several other integral components, including replacement of the air heaters at units 1, 2, 3, and 4. The WEPCO also plans to renovate major mechanical and electrical auxiliary systems and common plant support facilities. The WEPCO intends to perform the

work over a 4-year period, utilizing successive 9-month outages at each unit.

In its July 8, 1987 application for authority to renovate to the Public Service Commission of Wisconsin (PSC), WEPCO described the life extension project and explained its purpose and necessity. The WEPCO took care to distinguish the proposed renovation work from routine maintenance that did not require PSC approval, explaining that:

> . . . [work items] falling into the category of repetitive maintenance that are normally performed during scheduled equipment outages do not require specific commission approval and, accordingly, are not included in this application.

Thus, WEPCO's own earlier characterization of this project supports a finding that the planned renovations are not routine.

b. The purpose of the project is to significantly enhance the present efficiency and capacity of the plant and substantially extend its useful economic life. In its application to the PSC, WEPCO pointed out that due to age-related deterioration, total plant capability had declined by 40 percent. The company noted that the currently planned retirement dates for the Port Washington units, as set forth in its Advance Plan filed with the State, ranged from 1992 to 1999. However, WEPCO asserted that "extensive renovation of the five units and the plant common facilities is needed if operation of the plant is to be continued." In any event, WEPCO stated that the renovation work would allow the Port Washington plant to generate power at its designed capacity until the year 2010, and thus "represents a life extension of the units."

In contrast, in its July 29, 1988 letter to EPA headquarters (pages 9-13), WEPCO characterized the renovation work as the timely, routine correction of equipment problems – principally, the steam drum cracks. However, the information presented leads to the conclusion that this is not the case. While replacement of the steam drums is necessary to restore lost generating capacity, that is not the only work proposed to be done. Based upon maximum capacity figures for past years, it appears that the units had experienced deterioration in physical generating capacity even prior to the discovery of the steam drum cracks in 1984. Thus, WEPCO proposes a wide-ranging project encompassing a broad array of tasks that would not only correct the steam drum problem, but correct other age-related deterioration that is essentially independent of the steam drums. Such other work (e.g., replacement of air handlers) apparently is also necessary as a practical matter to restore original nameplate capacity. Thus, it appears that even if WEPCO had undertaken this renovation work immediately following discovery of the steam drum cracks, it would have been proper to characterize the proposed work as a nonroutine life extension project.).[1]

c. The work called for under the project is rarely, if ever, performed. The WEPCO's application to the PSC

[1] It is important to note in this regard that not all renovation, repair, or "life extension" projects would properly be characterized as modifications potentially subject to PSD and NSPS. For example, nonroutine repairs to correct unexpected equipment outages, even of major components such as steam drums, would not be subject to NSPS if they did not increase the maximum capacity of the affected facility as it existed prior to the outage. Conversely, undertaking a program of repair and maintenance properly characterized as routine would not subject a facility to the Act's requirements.

asserted that the work to be performed under the life extension project was not frequently done:

> Generally, the renovation work items included in this application are those that would normally occur only once or twice during a unit's expected life cycle.

The EPA asked WEPCO to submit information regarding the frequency of replacement of steam drums, the largest category of work item called for under the project. WEPCO reported that to date, no steam drums have ever been replaced at any of its coal-fired electrical generating facilities. WEPCO did point out that it had replaced other "headers" comparable in design pressure and function. However, the largest of these was 16 inches in diameter, and EPA does not believe that they are comparable in diameter, wall thickness, function, or importance to the rear steam drums at Port Washington.[2]

d. The work called for under the project is costly, both in relative and absolute terms. The latest information supplied by WEPCO is that the renovation work at Port Washington will cost $87.5 million, of which at least $45.6

[2] The WEPCO's July 29, 1988 letter to EPA stated (on page 13) that after further investigation, the company "learned of several examples" of steam drum failure and replacement. However, WEPCO provides no further details, other than noting that in one instance, the drum failed during initial testing and was replaced. Replacement of a failed component at a new facility presumably would not increase emissions from the facility, and probably would be viewed as routine if the alternative was to forego operation of that new facility. Under such circumstances, it is unlikely that the replacement would trigger the Act's requirements.

million is designated as capital costs.[3] The WEPCO reports that, in terms of annualized costs, the renovation project will cost $7.8 million, as compared to $51.6 million for a new 400 megawatt plant. Thus, renovation costs represent approximately 15 percent of replacements costs.

2. Change in the Method of Operation

The renovation work at Port Washington would not constitute a "change in the method of operation" within the meaning of the PSD regulations. However, it is clear that the "physical change" and "operational change" components of the "major modification" definition are discrete and independent. Thus, as explained below, PSD still applies if there is a physical change that will significantly increase net emissions.

In addition, the regulations exclude from the definition of physical or operational change "an increase in the hours of operation or in the production rate" [see 40 CFR 52.21(b)(2)(iii)(f)]. The preamble to the rule [45 FR 52676,

[3] The WEPCO's July 8, 1987 application to the PSC included a project cost estimate of $83.9 million, of which $45.6 million was designated as capital costs. A more recent cost estimate provided to EPA by WEPCO indicates that several work items are now deemed unnecessary, such that the cost of the original project is now estimated at $70.5 million. However, all but $89,000 of these reductions are designated as "maintenance" items. The recent submission also relates that the scope of the original project has now been expanded to include flue gas conditioning equipment and associated air heater work costing approximately $17 million. Although WEPCO has not broken down these additional costs into capital and maintenance (or "expense") expenditures, it would appear that most, if not all, of this additional work would be classified as capital costs. Thus, it is highly likely that actual capital costs would be significantly higher than $45.6 million.

52704 (August 7, 1980)], makes it clear that this exclusion is intended to allow a company to lawfully increase emissions through a simple change in hours or rate of operation up to its potential to emit (unless already subject to any federally enforceable limit) without having to obtain a PSD permit. Thus, emissions increases at Port Washington associated with increased operations would not, standing alone, subject WEPCO to PSD requirements. However, as discussed in greater detail below, the exclusion for increases in hours of operation or production rate does not take the project beyond the reach of PSD coverage if those increases do not stand alone but rather are associated with non-excluded physical or operational changes.

In its March 17, 1988 letter to Region V and its July 29, 1988 letter to EPA Headquarters, WEPCO asserted that the exclusion for increases in operational hours or production rate also would serve to render PSD review not applicable to the renovation work proposed at Port Washington because the project's purpose was to restore the original design capacity of 80 megawatts per unit, but not to exceed that level. However, a plant's original design capacity is irrelevant to a determination of PSD applicability.

B. Significant Net Emissions Increase

Under the PSD regulations, whether the life extension project at Port Washington would result in a "significant net emissions increase" depends on a comparison between the "actual emissions" before and after the physical changes resulting from the renovation work. Where, as here, the source has not yet begun operations following the renovation, "actual emissions" following the renovation are

deemed to be the source's "potential to emit" [see 40 CFR 52.21(b)(21)(iv)]. Apparently, there would be a "significant net emissions increase" within the meaning of the PSD regulations as a result of the proposed renovations as currently planned, because potential emissions after the project – reflecting the restoration of 80 megawatt capacity at each unit – would greatly exceed representative actual emissions prior to the physical changes. (The fact that the project is intended to restore the plant's original design capacity is irrelevant to that calculation.)[4] If this is so, the project would be a "major modification" subject to PSD review. However, PSD applies on a pollutant-specific basis, and EPA has not been furnished with adequate data regarding the impact of the proposed renovations on the various pollutants to determine whether a significant net emissions increase would indeed occur for any pollutant. Such data must be provided before EPA can make a final determination of PSD applicability.

It is important to note in this regard that WEPCO, at its option, could "net out" of PSD review by accepting federally enforceable restrictions on its potential to emit after the renovation. This could occur through enhancement of existing pollution control equipment, addition of

[4] The WEPCO also contends (July 29, 1988 letter, page 35) that EPA should instead compare representative actual emissions prior to the change with "projected" actual emissions after the renovations. The PSD regulations provide no support for this view. Where, as here, a source is not currently subject to a PSD permit containing operational limitations, EPA must presume, that the source will operate at its maximum capacity and, hence, its maximum potential to emit. However, as discussed below, a source is entitled to reduce its potential to emit by embodying its "projections" of future emissions in federally enforceable restrictions on its operations that may serve to lawfully avoid PSD review.

new equipment, acceptance of federally enforceable operational restrictions, or some combination of these measures, limiting potential emissions to a level not significantly greater than representative actual emissions prior to the renovations. Theoretically, WEPCO could minimize the needed restrictions on its potential to emit following the renovations if it could show that some period other than the most recent two years is "more representative of normal source operation" [see 52.21(b)(21)(ii)]. (Obviously, such a showing would be most important with respect to unit 5, because it has been shut down and has had zero emissions since 1985.) Since these matters are within WEPCO's control, you should advise the company to enter discussions with Region V and Wisconsin, as appropriate, if WEPCO desires to "net out" of PSD review.

The WEPCO also argued in its July 29, 1988 letter, at pages 33-41, that even if EPA is correct that the Port Washington life extension project would involve physical changes within the meaning of the PSD regulations, any emissions increases would be due to increased production rates or hours of operation rather than higher emissions per unit of production. Therefore, WEPCO contends that these increases should be excluded from consideration in determining whether a net significant emissions increase and, hence, a major modification, would occur. The WEPCO is incorrect in this regard.

As noted above, the exclusions cited by WEPCO are intended to apply where a source increases emissions by simply combusting a larger amount of fuel, or processing a larger amount of raw materials during a given time period, or by expanding its hours of operation "to take advantage of favorable market conditions" (see 45 FR 52704). In this instance, however, it is obvious that

WEPCO's plans to increase production rate or hours of operation are inextricably intertwined with the physical changes planned under the life extension project. Absent the extensive renovations proposed at Port Washington, WEPCO would have little market incentive to, and in part would be physically unable to, increase operations at these aged and deteriorated facilities which, absent the renovations, would likely be retired from service in the near future. Thus, WEPCO's plans call for precisely the type of "change in hours or rate or operation that would disturb a prior assessment of a source's environmental impact [and] should have to undergo [PSD review] scrutiny" (see 45 FR 52704). Conversely, accepting WEPCO's interpretation of the major modification regulations would serve to exclude from consideration all physical or operational changes except those which cause increased emissions per unit of production. Clearly, EPA never intended this result. It would allow, through substantial capital investment, significant expansion of the pollution-emitting capacity and longevity of major industrial facilities without PSD review of the impacts on air quality and opportunities for future economic growth.

C. Baseline Date

The November 9, 1987 letter from the Wisconsin Department of Natural Resources to Region V asked whether a complete March 28, 1986 PSD permit application for certain work at Port Washington triggered the PSD baseline date, despite the fact that the permit was never issued. The answer to this question is *yes*. Baseline dates are triggered by the first complete application and remain in effect regardless of whether the application is

revised or withdrawn, or whether the permit is finally issued and the source constructed or modified.

III. NSPS Applicability

The Port Washington renovations are subject to the Act's NSPS if they constitute "modifications" within the meaning of section 111 and 40 CFR Part 60. Under 60.1, the NSPS applies to modifications at an "affected facility." Each unit at Port Washington is properly characterized as an "affected facility" subject to the NSPS at 40 CFR Part 60, Subpart Da, which applies to electric utility steam generating units [see 60.40(a)]. Pursuant to 60.14(a), a modification for NSPS purposes is defined as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies." Increase in emission rate is in turn defined as an increase in kilograms per hour (kg/hr) [see 60.14(b)].

Pursuant to longstanding EPA interpretations, the emission rate before and after a physical or operational change is evaluated at each unit by comparing the hourly potential emissions under current maximum capacity to emissions at maximum capacity after the change. In addition, under the Act's NSPS provisions, only physical limitations on maximum capacity are considered in determining potential emissions at power plants. Thus, any prospective changes in fuel or raw materials accompanying the physical or operational change are not considered in determining maximum capacity. Consequently, 60.14(b)(2) requires that, in conducting emissions tests before and after a change to determine whether an increase in emission rate has occurred, "operational parameters" which may

affect emissions must be held constant. Fuel and raw materials are "operational parameters" for this purpose. Similarly, 60.14(e)(4) provides that use of an alternative fuel or raw material which the existing facility was designed to accommodate before the change would not be considered a modification. Thus, for example, a physical change which increases the maximum capacity of the facility would have a corresponding increase in the sulfur dioxide emissions if the facility used fuel with the same sulfur content before and after the change. Such a prospective increase cannot be offset by instead using fuel with a lower sulfur content after the change, because, under the regulations, the facility would always have the option of changing back to the higher sulfur-content fuel at a later date without triggering a modification for NSPS purposes. However, any offsetting reductions in emission rate caused by the concurrent addition of pollution control equipment would be considered in determining whether a physical or operational change results in an increase in emission rate.

The WEPCO contends (July 29, 1988 letter, at pages 20-27) that baseline capacity for the purpose of determining whether an increase in emission rate occurs for purposes of an NSPS modification is the original design capacity of the facility. This is incorrect. The thrust of the NSPS modification provisions is to compare actual maximum capacity before and after the change in question. Thus, original design capacity is irrelevant. The provision in 40 CFR 60.14(b)(2) for manual emission tests to determine whether an increase has occurred clearly contemplates that tests will be done just prior to and after the physical or operational change. The original design capacity of a unit, to the extent it differs from actual maximum

capacity at the time of the test due to physical deterioration – and, hence, derating – of the facility, is immaterial to this calculation.

A. Physical or Operational Change

As with the Act's PSD provisions, a modification occurs for NSPS purposes, if there is either a physical or operational change [see 40 CFR 60.14(a)].

1. Physical Change

As is the case under the PSD provisions, the proposed renovations at Port Washington would constitute a physical change for NSPS purposes, at least at units 2, 3, 4, and 5. The WEPCO would need to supply more information, if EPA is to make a definitive determination as to unit 1.

The rear steam drums are part of the steam generating unit which constitutes the "affected facility" within the meaning of 40 CFR 60.41(a), and the drum replacements at units 2, 3, 4, and 5 are integral to the planned increase in maximum capacity, which is the purpose of the life extension project. With respect to unit 1, other physical changes would increase maximum capacity from 45 to 80 megawatts. However, there is some question whether those changes, in significant part, would occur at the steam generating unit or will be limited to the turbine/generator set, which is not part of the affected facility. We suggest that you pursue this matter with WEPCO to the extent necessary to determine NSPS applicability regarding unit 1.

As with PSD, the NSPS regulations exclude routine maintenance, repair, and replacement [see 60.14(e)(2)].

B. Increase in Emission Rate

It seems clear that, absent some creditable offsetting changes, the increases in maximum generating capacity proposed for each of the Port Washington units would represent an increase in the hourly potential emission rate for each pollutant to which a standard applies over the emission rate prior to the renovation. As noted above, burning cleaner fuels would not be creditable. Similarly, voluntarily restricting the production rate following the renovations also would not be creditable for NSPS purposes, because WEPCO could, at a later date, increase production without triggering NSPS [see 40 CFR 60.14(e)(2)], Accordingly, to avoid triggering NSPS, WEPCO would need to install additional air pollution control equipment, or upgrade existing equipment, to offset the potential emissions increases, such that no increase would occur at maximum capacity. The information submitted indicates that WEPCO may plan some enhancement of the current control equipment, but it is unclear whether this would be adequate to prevent an increase in emission rates. As with PSD applicability, such steps can lawfully avoid NSPS requirements. Accordingly, you should advise the company that it should address these contingencies if it desires EPA to rule on whether WEPCO can avoid NSPS requirements in this fashion.

C. Reconstruction

Based upon data provided by WEPCO, it seems that the Port Washington renovations would not qualify as a "reconstruction" for NSPS purposes under 40 CFR 60.15, because the capital cost for the upgrades to each of the five units, while substantial, apparently is less than 50 percent of the fixed capital cost of constructing a comparable,

entirely new steam generating unit [see 60.15(b)(1)]. However, the modification and reconstruction provisions of NSPS are independent. The former provisions are intended to apply in circumstances where physical or operational changes which increase emissions make NSPS coverage appropriate at levels well below 50 percent of the capital cost of a replacement unit. Conversely, the reconstruction provisions are aimed at changes to an existing unit irrespective of associated emissions increases, but trigger NSPS requirements only if the higher 50 percent level is reached. Thus, the suggestion made by WEPCO in its July 29, 1988 letter (at pages 14-15) that EPA must undertake rulemaking to amend the reconstruction regulations before NSPS could be applied to the Port Washington project is not well taken.

IV. Conclusion

In adopting the PSD and NSPS programs, Congress sought to focus air pollution control efforts at an efficient and logical point: the making of long-term decisions regarding the creation or renewal of major stationary sources. The Port Washington life extension project, as it has been presented to EPA, would involve a substantial financial investment at pollution-emitting facilities that may significantly increase potential emissions of air pollutants over a period well beyond the current life expectancy of those facilities. If the additional factual information called for in this memorandum shows that emissions increases would indeed result from this project, the project would be subject to PSD and NSPS requirements. Such a result would be in harmony with the broad policy objectives that Congress intended to achieve through these programs.

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